RAZOR ENERGY CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

March 28, 2019

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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.

"**Action**" has the meaning attributed thereto in "*Legal Proceedings and Regulatory Actions*".

"**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 March 28, 2019 for the financial year ended December 31, 2018.

"**AIMCo**" means Her Majesty the Queen in Right of Alberta by its agent, Alberta Investment Management Company.

"**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.

"**Consolidation**" means the share consolidation of the Company on the basis of one post-Consolidation Common Share for every 20 pre-Consolidation Common Shares.

"**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.

"**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 13, 2019 and effective December 31, 2018.

"**Swan Hills Acquisition**" means the acquisition of certain oil and gas assets located in the Swan Hills area of Alberta from an arm's length public oil and gas company for aggregate consideration of $15.6 million, including customary closing and post-closing reconciliation adjustments.

"**Term Loan Facility**" has the meaning attributed thereto in "*Three Year History - Financial Year Ended December 31, 2017*".

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

"**Vector**" means Vector Resources Inc., a CPC company incorporated under the *Business Corporations Act* (Ontario).

"**Vector Shares**" means the Common Shares prior to the closing of the Arrangement and prior to giving effect to the Consolidation.

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, 2018, 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

NOTE ON SHARE REFERENCES

The Common Shares were consolidated on the basis of one post-Consolidation Common Share for every 20 Vector Shares on January 31, 2017. References in this AIF to Common Shares are on a post-Consolidation basis. References in this AIF to pre-Consolidation Common Shares or Vector Shares refer to the Common Shares prior to the Consolidation. Readers should divide any referenced number of Vector Shares by 20 to arrive at the equivalent number of Common Shares.

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;
- 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:

- 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.

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:

- 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 April 15, 2011, the Company filed articles of amendment to change its name from "2236235 Ontario Inc." to "Vector Resources Inc." On June 29, 2011, the Company filed articles of amendment to remove share transfer restrictions in its articles.

On September 28, 2011, the Company completed its initial public offering. The Company was classified as a CPC as described in the policies of the TSXV. As a result, Vector's business was to identify and evaluate businesses and assets with a view to completing a qualifying transaction.

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 completed the Consolidation and changed its name from "Vector Resources Inc." 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 4000, 421 - 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

As at the date hereof the Company has three wholly-owned subsidiaries, Razor Resources Corp., Blade Energy Services Corp., and Razor Power 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, 2016

On November 15, 2016, Vector entered into a letter agreement with Razor Private in respect of a proposed business combination and, on December 29, 2016, entered into the arrangement agreement ("Arrangement Agreement") in respect of the Arrangement. Pursuant to the Arrangement, each common share of Razor Private was exchanged for 2,042.13 Vector Shares to complete the Company's Qualifying Transaction.

Financial Year Ended December 31, 2017

On January 31, 2017, the Company completed the Arrangement, which constituted the Company's Qualifying Transaction. Pursuant to the Arrangement, each common share of Razor Private was exchanged for 2,042.13 Vector Shares. Former shareholders of Razor Private received an aggregate of 179,525,708 Common Shares of the Company on a pre-Consolidation basis.

On January 31, 2017, the Company secured a non-revolving term loan facility from AIMCo for a principal amount of $30.0 million (the "**Term Loan Facility**"). The Term Loan Facility has a four year term with an interest rate of 10% and is payable semi-annually. A portion of the Term Loan Facility was used by the Company to fund the purchase price in respect of the Swan Hills Acquisition. The remaining proceeds of the Term Loan Facility were be used by the Company to fund its development program and for general corporate purposes. The Company also issued Common Shares to AIMCo, representing approximately 10.05% of the Common Shares, at the time of issuance, as additional consideration for the Term Loan Facility.

On January 31, 2017, the Company completed the Swan Hills Acquisition, pursuant to which the Company acquired certain oil and gas interests in the Swan Hills area of Alberta for aggregate cash consideration of $15.8 million, including customary closing and post-closing reconciliation adjustments.

On January 31, 2017, the Company completed the Consolidation and filed articles of amendment to change its name from "Vector Resources Inc." to "Razor Energy Corp.".

On May 15, 2017, the Company closed a prospectus financing of 5,750,000 subscription receipts at a price of $3.00 per subscription receipt for gross proceeds of $17.3 million (net proceeds of $15.5 million).

On May 24, 2017, the Company completed the Kaybob Acquisition, pursuant to which the Company acquired certain oil and gas interests in the Kaybob area of Alberta for aggregate cash consideration of $12.3 million, including customary closing and post-closing reconciliation adjustments. In connection with the closing of the Kaybob Acquisition, on May 24, 2017, each subscription receipt was converted to one common share of the Company and one-half of one common share purchase warrant of the Company. Each whole warrant is exercisable into one common share of the Company at an exercise price of $3.50 per common share and expired on May 24, 2018.

On December 18, 2017, the Company acquired additional working interest positions to consolidate its existing Kaybob Triassic Units 1 & 2 for aggregate cash consideration of $4.6 million, including customary closing and post-closing reconciliation adjustments.

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 terms of the Amended Term Loan Facility are materially unchanged from the Term Loan Facility. Principal continues to be due 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.

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 yield and growth oriented light oil weighted company operating in Alberta. 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 yield and 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 up to five years of technically viable field operational activities;
4. manage uncertainty through the technical and operating experience Razor has in each of these geographic areas:
5. attract skilled and experienced labour and acquire equipment to vertically integrate certain service functions where Razor has a defined internal market; and
6. explore and execute on power related projects for internal consumption and third party sales.

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.

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, 2018, the Company had 33 employees (comprised of 28 head office and 5 field employees), and 4 contract employees at the head office. In addition, the Company utilizes the services of contractor operators in its field operations.

Reorganizations

Other than as disclosed in *"General Development of the Business - Financial Year Ended December 31, 2016" and "General Development of the Business - Financial Year Ended December 31, 2017"*, 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, 2018

The reserves data herein is based upon the Sproule Report. The reserves data set forth below is based upon an evaluation of the Sproule Report. 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 COGE Handbook 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, 2018 and based on the Sproule December 31, 2018 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.

New And Revised Reserves Evaluation Guidelines And Best Practices For Industry Stakeholders

For greater transparency and accuracy of current values and future cash flows, Razor has elected to adopt and incorporate the updated abandonment, decommissioning and reclamation costs ("ADR") and inactive well costs ("IWC") best-practice recommendations into the Company's 2018 year-end reserves report.

In 2018 the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and associated industry professionals updated the Canadian Oil and Gas Evaluations ("COGE") Handbook. The updates clarify and streamline existing guidelines and offer additional guidance regarding Canadian reserves evaluations.

With respect to ADR Costs, the SPEE provided increased guidance for sustainable best practices. Acknowledging the social and environmental responsibility of the oil and gas industry, the COGE Handbook supports the premise that ADR costs should always be considered in the evaluation process and each report must clearly describe the ADR costs included and excluded from the report. The COGE Handbook recommends that partial disclosure of ADR is not considered best practice. To avoid confusion, the exclusion of all ADR costs is preferential to partial inclusion.

With respect to Operating Costs, the SPEE provided broader guidance for IWC and maintenance capital. There is a material change to COGE Handbook guidance with respect to active and inactive costs. Inactive costs such as mineral leases, shut-ins, suspended and capped well-operating costs, etc. should be included in the evaluation to properly represent the assets being evaluated but forecast separately from active asset costs at the property or corporate level, so economic production entities are not unduly burdened.

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, 2018

	Light, Medium & Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Barrels of Oil Equivalent	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(Mbbl)	(Mbbl)	(Mmcf)	(Mmcf)	(Mbbl)	(Mbbl)	(MBOE)	(MBOE)
Proved								
Developed producing	8,363	6,540	7,682	7,258	2,550	2,022	12,194	9,772
Developed non-producing	1,136	969	948	901	341	272	1,635	1,391
Undeveloped	1,382	1,275	536	501	116	105	1,569	1,447
Total Proved	**10,881**	**8,784**	**9,166**	**8,660**	**3,007**	**2,399**	**15,398**	**12,610**
Total Probable	3,410	2,748	2,732	2,575	942	786	4,825	3,979
Total Proved plus Probable	**14,291**	**11,532**	**11,898**	**11,235**	**3,949**	**3,185**	**20,223**	**16,589**

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, 2018

	Before Income Tax Discounted at Various Rates				Unit Value Before Income Tax
	0%	**5%**	**10%**	**15%**	**Discounted at 10%**
Description	M$	M$	M$	M$	$/BOE
Proved					
Producing	156,661	169,270	148,671	128,361	15.21
Developed non-producing	41,365	30,169	23,183	18,484	16.67
Undeveloped	47,600	34,804	25,879	19,553	17.88
Total Proved	**245,626**	**234,243**	**197,733**	**166,398**	**15.68**
Total Probable	151,287	89,509	58,854	41,540	14.79
Total Proved plus Probable	**396,913**	**323,752**	**256,587**	**207,938**	**15.47**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2018 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
	0%	**5%**	**10%**	**15%**	**Discounted at 10%**
Description	**M$**	**M$**	**M$**	**M$**	**$/BOE**
Proved					
Producing	107,322	131,788	118,754	103,577	12.15
Developed Non-producing	30,449	21,909	16,631	13,098	11.96
Undeveloped	34,425	24,223	17,099	12,095	11.82
Total Proved	**172,196**	**177,920**	**152,484**	**128,770**	**12.09**
Total Probable	115,444	66,267	42,558	29,396	10.70
Total Proved plus Probable	**287,640**	**244,187**	**195,042**	**158,166**	**11.76**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2018 as detailed below.
(2) Values are net of ADR and IWC.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
(FORECAST PRICES AND COSTS)
AS OF DECEMBER 31, 2018

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	1,159,911	216,001	516,048	42,725	139,511	245,626	73,429	172,197
Total Proved Plus Probable	1,579,106	292,501	688,557	60,647	140,490	396,913	109,273	287,640

FUTURE NET REVENUE BY PRODUCT TYPE
(FORECAST PRICES AND COSTS)
AS OF DECEMBER 31, 2018

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)	197,284	15.74
	Conventional Natural Gas including associate byproducts	449	6.11
Proved Plus Probable	Light and Medium Crude Oil (including solution gas liquids)	255,997	15.52
	Conventional Natural Gas including associate byproducts	590	6.14

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, 2018, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
(FORECAST PRICES AND COSTS)
AS OF DECEMBER 31, 2018

Year	WTI Oil ($US/Bbl)(1)	Light Sweet Edmonton Oil ($Cdn/Bbl)(2)	AECO ($Cdn/MMBTU)(4)	Exchange Rate ($US/$CDN)
Forecast				
2019	63.00	75.27	1.95	0.77
2020	67.00	77.89	2.44	0.80
2021	70.00	82.25	3.00	0.80
2022	71.40	84.79	3.21	0.80
2023	72.83	87.39	3.30	0.80
2024	74.28	89.14	3.39	0.80
2025	75.77	90.92	3.49	0.80
2026	77.29	92.74	3.58	0.80
2027	78.83	94.60	3.68	0.80
Thereafter		Escalation Rate of 2% per year		

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) Medium Crude 29 degrees API 2.0% sulphur at Cromer.
(4) 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, 2018, was $68.47/Bbl for light crude oil, $33.71/Bbl for NGLs and $2.01/Mcf for natural gas.

	Q4-2018	Q3-2018	Q2-2018	Q1-2018	Q4-2017	Q3-2017	Q2-2017	Q1-2017
Average selling price								
Oil price ($/bbl)	43.63	80.80	79.71	69.76	68.14	54.79	58.73	61.99
NGL price ($/bbl)	28.86	35.70	34.37	35.89	34.72	26.38	26.38	24.20
Gas price ($/mcf)	2.03	1.86	1.74	2.42	1.85	1.57	2.53	2.44
Benchmark prices and foreign exchange rates								
OIL ($/bbl)								
WTI (USD)	59.10	69.75	68.05	62.91	55.35	48.17	48.24	51.86
WTI (CAD)	77.98	91.17	87.87	79.58	70.39	60.34	64.93	68.63
CAD/USD EXCHANGE RATE	0.76	0.76	0.78	0.79	0.79	0.80	0.74	0.76
WTI vs Light Sweet Edmonton Oil differential (CAD/bbl)	(37.40)	(12.63)	(8.98)	(7.27)	(1.72)	(3.31)	(3.01)	(4.71)
NATURAL GAS (CAD/mcf)								
AECO NGX AB-5a	1.57	1.19	1.25	2.08	1.70	1.45	2.81	2.72
AECO NGX AB-7a	1.90	1.35	1.04	1.87	1.95	2.04	2.79	2.95

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 utilizing a 2% annual inflation rate. These expenditures are expected to occur between 2019 and 2068.

	Discounted at Various Rates			
	0%	**5%**	**10%**	**15%**
Description	M$	M$	M$	M$
Abandonment, decommissioning and reclamation costs ("ADR")	137,962	51,673	28,069	19,187
Inactive well costs ("IWC")	34,313	26,718	21,226	17,922
Total	172,275	78,391	49,295	37,109

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, 2017 to December 31, 2018, using forecast prices and costs.

	Proved (Mbbls)	Proved plus probable (Mbbls)
Opening balance, beginning of year	15,072	20,327
Acquisitions, net of dispositions	1,040	1,269
Technical Revision	1,075	417
Less Production	(1,790)	(1,790)
Total Reserves, end of year	**15,397**	**20,223**

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. 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 nine horizontal wells in the Beaverhill Lake formation in Swan Hills. An additional six horizontal Beaverhill Lake wells 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
2019	1,585	1,990
2020	12,521	24,561
2021	28,619	34,096
2022	—	—
Thereafter	—	—
Total Undiscounted	42,725	60,647
Total Discounted at 10%	35,929	51,482

Future development costs are capital expenditures required in the future for Razor to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $42.7 million for proved reserves and $60.6 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.

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, 2018, the assets included 194,880 gross (158,690 net) acres of total land, of which 65,600 gross (60,613 net) acres were booked as undeveloped land. The assets at Swan Hills include 1,330 gross (650 net) wells in total, of which 310 gross (131 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 sales production from the area for the month ended December 31, 2018 averaged 3,570 BOE/d comprised of 65% light oil, 23% NGL's and 12% natural gas.

Kaybob

The Kaybob area is located in west central Alberta approximately 250 km northwest of Edmonton. As at December 31, 2018, the assets included 131,440 gross (67,680 net) acres of total land, of which 17,360 gross (6,173 net) acres were booked as undeveloped land. The assets at Kaybob include 365 gross (207 net) wells in total, of which 75 gross (42 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 sales production from the area for the month ended December 31, 2018 averaged 1,337 BOE/d of which 84% was light oil and NGLs.

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.

2019 Budget

For fiscal 2019, the Board has approved a capital budget of $13.5 million, which includes end of life expenditures, reactivations, recompletions and optimizations in both the Swan Hills and Kaybob areas. Also included are certain production management activities of existing waterfloods which will complement current production levels while enhancing long term recoveries of oil in place.

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, 2018. All of the wells were located onshore in the province of Alberta.

	Producing				Non-Producing (3)					
	Light Oil		Gas		Light Oil		Gas		Other	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Operated	145	131	3	3	416	342	17	13	204	170
Non-operated	218	35	19	4	326	77	89	21	258	60
Total	**363**	**166**	**22**	**7**	**742**	**419**	**106**	**34**	**462**	**230**

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. Abandoned wells are not included in the Table.

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, 2018.

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	82,960	66,786	243,360	159,584	326,320	226,370
Total	**82,960**	**66,786**	**243,360**	**159,584**	**326,320**	**226,370**

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 758 net acres of undeveloped land holdings may expire by December 31, 2019. 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, 2018 and which can be found on SEDAR at www.sedar.com.

Tax Horizon

For the fiscal year end December 31, 2018, the Company paid no income tax and has approximately $69.3 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 2019 taxation year.

Costs Incurred

The following table summarizes Razor's property acquisition costs, exploration costs and development costs for the year ended December 31, 2018.

Expenditure	Year Ended December 31, 2018 ($000s)
Property acquisition costs	3,921
Corporate acquisition costs	28
Development costs	33,758
Other	1,527
Total	39,234

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, 2019, 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)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	(BOE/d)
Proved				
Swan Hills	2,115	1,823	709	3,128
Kaybob	916	1,050	139	1,230
Total Proved	**3,031**	**2,873**	**848**	**4,358**
Probable				
Swan Hills	48	37	15	68
Kaybob	13	26	3	21
Total Probable	**61**	**63**	**18**	**89**
Total Proved plus Probable	**3,092**	**2,936**	**866**	**4,447**

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:

	2018 Quarter Ended				Year Ended
	Q4	Q3	Q2	Q1	December 31
	Dec. 31	Sept. 30	June 30	March 31	2018
Average Daily Production[1]					
Light Oil (Bbls/d)	2,994	3,271	3,274	3,032	**3,143**
Natural gas liquids[2] (Bbls/d)	3,225	4,505	4,056	3,286	**3,770**
Conventional natural gas (Mcf/d)	1,374	1,238	1,074	774	**1,117**
Combined (BOE/d)	4,906	5,260	5,023	4,353	**4,888**
Average Daily Sales Volumes[1]					
Light Oil (Bbls/d)	2,611	3,271	3,274	3,032	**3,046**
Natural gas liquids[2] (Bbls/d)	3,225	4,505	4,056	3,286	**3,770**
Conventional natural gas (Mcf/d)	1,374	1,238	1,074	774	**1,117**
Combined (BOE/d)	4,523	5,260	5,023	4,353	**4,792**
Average Price Received					
Light Oil ($/Bbl)	43.63	80.80	79.71	69.76	**70.37**
Natural gas liquids ($/Bbl)	28.86	35.70	34.37	35.89	**33.51**
Conventional natural gas ($/Mcf)	2.03	1.86	1.74	2.42	**1.80**
Combined ($/BOE)	36.71	59.85	61.05	56.76	**53.97**
Royalties Paid[3]					
Light Oil ($/Bbl)	11.83	20.87	12.75	12.32	**12.20**
Natural gas liquids ($/Bbl)	9.82	12.95	6.78	7.17	**8.27**
Conventional natural gas ($/Mcf)	(11.64)	(9.74)	(10.94)	(12.44)	**(11.08)**
Combined ($/BOE)	9.34	13.96	8.61	12.70	**11.18**
Production Costs[3]					
Light Oil ($/Bbl)	24.53	32.96	32.63	25.80	**29.26**
Natural gas liquids ($/Bbl)	24.53	32.96	32.63	25.80	**29.26**
Conventional natural gas ($/Mcf)	4.09	5.49	5.44	4.30	**4.88**
Combined ($/BOE)	24.53	32.96	32.63	25.80	**29.26**
Netback Received[3][4]					
Light Oil ($/Bbl)	7.27	26.97	34.33	31.64	**28.91**
Natural gas liquids ($/Bbl)	(5.49)	(10.21)	(5.04)	2.92	**(4.01)**
Conventional natural gas ($/Mcf)	9.58	6.10	7.24	10.56	**8.01**
Combined ($/BOE)	2.84	12.93	19.81	18.26	**13.53**

Notes:

1) Before deduction of royalties. Production volumes exceeded sales volumes in Q4 2018 as the Company commenced discretionary oil inventory builds in response to high Light Sweet Edmonton Oil differentials compared to WTI.
2) Liquids include light and medium oil, heavy oil and associated NGLs.
3) Razor did not record operating expenses or royalties on a commodity basis. Information in respect of operating expenses and royalties for 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 liquids ($/Bbl) and natural gas ($/Mcf) is calculated using operating expense and royalty figures for 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, 2018 for each of the important properties comprising Razor's assets:

	Light and Medium Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	(BOE/d)
Swan Hills	2,175	2,412	933	3,509
Kaybob	968	1,358	184	1,379
Total	3,143	3,770	1,117	4,888

The average production for the year ended December 31, 2018 was 89% liquids; and for the year ended December 31, 2018, 97% of gross revenue was derived from liquids production.

INDUSTRY CONDITIONS

Restrained Pipeline Capacity and Differential Volatility

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, backedup 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 approval by both the National Energy Board of Canada ("NEB") and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on 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 as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, including the United States, and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's indigenous consultations. The Federal Court of Appeal quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Federal Court of Appeal's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to

Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations, notwithstanding the fact that project-related marine shipping may have a significant adverse effect on the marine environment. Cabinet has three months to consider the NEB's report and, subject to a new round of indigenous consultation, decide whether it will approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, preconstruction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Additionally, Bill C-48, the *Oil Tanker Moratorium Act*, continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast.

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/d of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first rail cars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to $4 per barrel; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. Little is known about this strategy, but the deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

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. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada 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. Additionally, while a number of LNG 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. 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.

Availability of Services

The availability of services and personnel necessary to carry out the reactivation, re-entry, optimization, facility, pipeline, end of life operations that form a substantial portion of the Company's planned 2019 development program is reasonably healthy. The Company will take necessary steps to adjust its program in the event external conditions arise that may constrain availability of services and personnel due to increased demand and competition.

Legislation and Regulation

The oil and natural gas industry is 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 oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of the Company 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 oil and natural gas industry are described further below.

Pricing and Marketing - Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of 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, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

On July 6, 2012, the federal government enacted the Jobs, Growth and Long-term Prosperity Act which made amendments to the National Energy Board Act ("**NEB Act**") that affect the NEB's export and import framework. As a result of these changes, the NEB issued the Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act ("**Interim Oil and Gas MOG**"). The purpose of the Interim Oil and Gas MOG is to provide guidance to applicants until such time as the NEB has completed the review and update of the regulatory framework. As part of the review and update, the NEB is currently proposing amendments to the *National Energy Board Part VI (Oil and Gas) Regulations and the National Energy Board Export and Import Reporting Regulations*.

In February 2018, the federal government issued Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts* (Bill C-69), which among other things, proposes changes to the NEB regime. The changes proposed in Bill C-69, if and when adopted into law, do not materially alter the current requirements around oil exports. However, at this stage, it is not certain whether or when the federal government might issue new or revised regulations that might impact the oil export regime currently in place.

Pricing and Marketing - Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations. Natural gas prices in Alberta have been constrained in recent years due to increasing supply in North America, limited access to markets and limited storage capacity.

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7% short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019 limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d-a reduction of approximately 8.7% from the total daily average oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 bbl/d to a maximum output of approximately 3.63 million bbl/d. Razor is not subject to a curtailment order.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada U.S. Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

On November 30, 2018, U.S. President Trump, Prime Minister Trudeau, and former Mexican President Enrique Pena Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when and if the USMCA will be ratified.

As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the final ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry, including the Company's business.

Trans-Pacific Partnership and Other Trade Agreements

Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force for the first six countries to ratify the agreement: Canada, Australia, Japan, Mexico, New Zealand, and Singapore. On January 14, 2019, the CPTPP came into force for Vietnam.

Canada has also pursued a number of other international free trade agreements with countries around the world. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017.

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

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state-owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state-owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA is punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9 million in total liability.

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 liquids, sulphur and natural gas production. Royalties payable on production from minerals other than Crownowned 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 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 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, the federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

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

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit was available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, subject to certain maximum amounts. The maximum credits available were determined by a company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2011. The new well incentive program applies to certain wells beginning production of conventional oil and natural gas after April 1, 2009 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum volume including all products of 7,949 cubic metres equivalent for oil wells and 14,100 cubic metres equivalent for gas wells.

On May 27, 2010, the Government of Alberta announced changes to the existing royalty framework under the Petroleum Royalty Regulation, 2009 and the Natural Gas Royalty Regulation, 2009 which became effective January 1, 2011 (the "**Alberta Royalty Framework**"). Changes include making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the Alberta Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. An Emerging Resources and Technologies Initiative has also been created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells. In particular, pursuant to the Emerging Resource and Technologies Initiative: (a) coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 million cubic feet ("**Mmcf**") of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010; (c) horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 Mmcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and (d) horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

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.

Climate Change Regulation

Federal

In common with all producers, the Company's exploration activities and production facilities emit carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases" ("**GHG**").

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 an ambitious goal of holding the increase in global average temperature to well below 2°C above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

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. 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 (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework. Prior to the release of the Framework, the federal government announced in October 2016 that it will 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. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be 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. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it will take effect in the Yukon and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime and New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

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 into force until 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. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 Mt by 2030.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45 percent below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

In December 2017, Environment and Climate Change Canada ("**ECCC**") published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the federal Greenhouse Gas Reporting Program (**"GHGRP"**). The Notice with respect to reporting of greenhouse gases for 2017, which was published on December 30, 2017 in Part I of the Canada Gazette, outlines the 2017 reporting requirements for GHG-emitting facilities. In December 2017, ECCC published its updated requirements and step-by- step reporting instructions in advance of the 2017 reporting period under the GHGRP. Starting in the 2017 reporting year, the GHGRP will apply to a wider range of GHG emitting operations in Canada, as the reporting threshold was lowered from 50,000 tonnes to 10,000 tonnes of CO2e. All facilities that emitted the equivalent of 10,000 tonnes of CO2e in 2017 were required to submit a report by June 1, 2018.

IIn 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. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. The proposed regulations to implement CFS are not anticipated to be enacted until mid-2019.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45% below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

It is expected that additional regulations eventually implemented by the Government of Canada will have an impact on the oil and gas industry as a whole, which could result in increased costs for the Company to comply with such legislation. There remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and how such targets will be achieved. In the meantime, the Company will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions.

Alberta

On July 1, 2007, the Specified Gas Emitters Regulation ("**SGER**") came into force under Alberta's Climate Change and Emissions Management Amendment Act requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually ("**Regulated Emitters**") to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels).

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership Report, the Government of Alberta announced its Climate Leadership Plan which introduced a carbon tax on all emitters beginning January 1, 2017 at $20 per tonne of GHG emissions, increasing to $30 per tonne in January 2018. An oil sands specific approach was also introduced to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was introduced for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Carbon pricing was also identified by the Climate Advisory Panel as the primary policy tool for reducing emissions in the province. On June 23, 2016, the Alberta legislature passed the Climate Leadership Implementation Act (Bill 20) which furthers the implementation of the Climate Leadership Plan. Details of Alberta's carbon pricing model were detailed in its April 2016 budget, which earmarks almost $8.5 billion to build and modernize major public infrastructure. Budget 2016 also allocates $634 million to various climate change initiatives in addition to funds for roads and bridges, flood recovery and municipal infrastructure support. The Act came into force on January 1, 2017 and empowers the provincial government to impose a carbon levy in the province. As of January 1, 2017, a $20 per tonne carbon levy will be applied to fuels that emit GHG when combusted. This levy increased to $30 per tonne in 2018. Fuels covered by the levy include transportation and heating fuels such as diesel, gasoline, natural gas and propane. It will not apply directly to consumer purchases of electricity. Revenues from the carbon levy will be used for initiatives to reduce GHG emissions and to fund carbon rebates, as well as for investments in clean technology and green infrastructure. The carbon levy will also be used for an "adjustment fund" to help individuals and families, small business and First Nations adjust. While the levy is anticipated to increase again in 2021, in line with the federal legislation, the Government of Alberta has announced that it will not proceed with the 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds.

On January 1, 2018, the Carbon Competitiveness Incentive Regulation ("**CCI Regulation**") replaced the SGER. Under the CCI Regulation, facilities are allowed to emit a certain amount of GHG, free of charge from the carbon levy. This approach is designed to protect industries from competitiveness impacts that could shift production to other jurisdictions. The CCI Regulation applies to facilities that emitted 100,000 tonnes or more of GHG in 2003, or a subsequent year. A facility with less than 100,000 tonnes of GHG may be eligible to opt-in to the CCI Regulation if it competes against a facility regulated under the CCI or has more than 50,000 tonnes of annual emissions, high emissions-intensity and trade-exposure (by opting in, facilities become exempt from the application of the carbon levy for fuels whose emissions are included in their site reporting). Under the updated system, a facility will receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions are above the amount freely permitted, they will be required take one or more of the following actions to bring the facility into compliance:

- make improvements at their facility to reduce emissions intensity;
- use emission performance credits generated at facilities that achieve more than the required reductions;
- purchase Alberta-based carbon offset credits; or
- contribute to Alberta's Climate Change and Emissions Management Fund.

Emissions from the oil sands sector (which account for approximately one-quarter of Alberta's annual emissions) have been capped at 100 Mt per year. This cap has been legislated in the Oil Sands Emissions Limit Act (Bill 25), which was introduced in November 2016. The legislation contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments). Bill 25 came into force on December 14, 2016.

In January 2018, the Alberta government also announced that it is adopting ECCC's greenhouse gas reporting requirements for the 2017 reporting period, meaning that facilities emitting 10,000 tonnes of CO_2e or more must submit a specified gas report to Alberta Climate Change Office via ECCC's SWIM reporting system (the reporting threshold for previous years is 50,000 tonnes of CO_2e). Facilities were required to report their 2017 greenhouse gas emissions to ECCC's SWIM system by June 1, 2018.

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 fresh water 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. The Canadian Environmental Protection Act and the Canadian Environmental Assessment Act, provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On February 8, 2018, the Government of Canada introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to Bill C-69, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on:
(i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process;

(ii) potentially increased public participation where the project undergoes a panel review;(iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public- interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government;
(iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and
(v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities.

Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced Bill C-48, the Oil Tanker Moratorium Act in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

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 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

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**LLR Program**") 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. 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.

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which were implemented through this three year process include: (a) increases to the prescribed average reclamation cost for each individual well or facility (which increased a licensee's deemed liabilities); (b) increases to facility abandonment cost parameters for each well equivalent (which increased a licensee's deemed liabilities); (c) use of an industry netback averaged over the last three years (which affected the calculation of a licensee's deemed assets); and (d) a change to the present value and salvage factor, which increases to 1.0 for all active facilities from 0.75 for active wells and 0.50 for active facilities (which increased a licensee's deemed liabilities).

The changes were implemented over a three-year period, ending August 2015. The first phase was implemented in May 2013, the second phase was implemented in May 2014 and the final phase was implemented in August 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

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

Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. The AER's Directive 67 was amended and now requires extensive corporate governance and shareholder information, with a focus on any previous insolvency proceedings in order to acquire or transfer licenses needed to operate wells and facilities. The AER will consider and process all applications for licence eligibility under Directive 067: Applying for Approval to Hold EUB Licences as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee eligibility approval if appropriate in the circumstances. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer. The AER may implement additional changes in response to the final Redwater decision.

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 completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19 percent of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

On January 31, 2019, the Supreme Court of Canada ("**SCC**") ruled on the appeal of Redwater in Orphan Well Association v. Grant Thornton Limited, 2019 SCC 5, in favour of the AER and Orphan Well Association. Specifically, the SCC held that while trustees will not be personally liable for abandonment and reclamation obligations, the estate will remain liable for such obligations. As a result, reclamation and abandonment liabilities must be dealt with before there can be any distribution to the insolvent parties' creditors, including its secured creditors. In response to the SCC's decision, the AER is working on an improved liability management framework. Razor cannot predict what the AER's improved framework may look like but such pending changes to the AB LLR Program will have an impact on crude oil and natural gas production in Alberta, including Razor's business.

Land Tenure

Crude oil and natural gas located in the Western Canadian provinces is owned both by the respective provincial governments and by private individuals. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying periods and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Where oil and natural gas is privately owned, rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

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. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

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.

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 Razor'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**"); 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 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 Razor'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. Razor'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, 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 Razor'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.

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 continues to affect the oil and natural gas industry and limit 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 and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the 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 government of Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Capital Lending Markets

As a result of recent economic uncertainties in the oil and 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 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 and processing and storage facilities and operational problems affecting such pipelines 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 gas business.

Exploration and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by the Company will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Company currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.
Future oil and 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 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 and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

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, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial conditions.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries 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. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. 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.

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, property damage, property tax, land rights, the environment 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.

The Company is named as a defendant in the Action. See "*Legal Proceedings and Regulatory Actions*". While management of the Company does not believe that this action 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 Action 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. Although the Company is of the view that an injunction is unlikely to be granted to prohibit the acquisition of the assets described in the Action, no assurance can be given to that effect.

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. Since the 2016 U.S. presidential election, the U.S. has withdrawn from the TPP and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, and Canada, the U.S. and Mexico signed the Canada-United States-Mexico Agreement which will replace NAFTA once ratified by the three signatory countries. See "Industry Conditions - The North American Free Trade Agreement". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is presently unclear how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the United States administration mayhave a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Razor.

In addition to the political disruption in the United States, the citizens of the United Kingdom have voted to withdraw from the European Union and the Government of the United Kingdom has begun taking steps to implement such withdrawal. 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. 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 Razor'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.

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

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time.

Insurance

Razor's involvement in the exploration for and development of oil and gas properties may result in Razor becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Razor 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, Razor 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 Razor. The occurrence of a significant event that Razor is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Razor's financial position, results of operations or prospects.

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 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 supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; 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

Razor anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Razor's future revenues or reserves decline, Razor 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 Razor. Moreover, future activities may require Razor to alter its capitalization significantly. The inability of Razor to access sufficient capital for its operations could have material adverse effect on Razor's financial condition, results of operations or prospects.

Competition

Razor will actively compete for acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Razor. Razor's competitors will include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Razor's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personnel resources available to them than Razor.

Razor's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the 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. 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 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, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. 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 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. 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 and 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 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. 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. 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 and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates, and such variations could be material.

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond the Company's control, and no assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

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.

Estimates with respect to resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of resources, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same resources based upon production history will result in variations, which may be material, in the estimated resources.
Prospective resources are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources.

Resources estimates may require revision based on actual production experience. Market price fluctuations of natural gas prices may render uneconomic the recovery of the resources.

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 response to the Supreme Court's decision, the AER is also working on an improved liability management framework. Razor cannot predict what the AER's improved framework may look like but such pending changes to the AB LLR Program will have an impact on crude oil and natural gas production in Alberta, including Razor's business.

The AER's new liability management framework 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. As a result of the decision in Redwater, 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*".

Income Taxes

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.

Climate Change

Razor's exploration and production facilities and other operations and activities emit GHGs and which may require Razor 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. Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Company operates. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on Razor and its operations and financial condition. See *"Industry Conditions"*.

Reserve Replacement

Razor's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Razor successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Razor may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Razor's reserves will depend not only on Razor'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 Razor'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 Razor has an interest. As a result, Razor will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Razor's financial performance. Razor's return on assets operated by others will therefore depend upon a number of factors that may be outside of Razor's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reliance on Key Personnel

Razor's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on Razor's business, financial condition, results of operations and prospects. Razor does not have any key person insurance in effect. The contributions of the existing management team to Razor'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 Razor 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 Razor's management.

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 may have a material adverse effect on the Company's results of operations and business.

Permits and Licences

The operations of Razor may require licences and permits from various governmental authorities. There can be no assurance that Razor 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

Razor's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Razor 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 Razor to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Razor's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Razor's ability to expend the necessary capital to replace its reserves or to maintain its production. If Razor'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.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time could be updated or revisited and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may be impacted if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditures using funds from operations.

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 Razor's reserves as determined by independent evaluators. Furthermore, an increase in interest rates could result in a significant increase in the amount the Company pays to service debt.

Issuance of Debt

From time to time, Razor 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 Razor's debt levels above industry standards. Neither Razor's articles of incorporation nor its by-laws limit the amount of indebtedness that Razor may incur. The level of Razor's indebtedness from time to time could impair Razor's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Razor's ability to meet its debt service obligations will depend on Razor's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Razor. As certain of the indebtedness of Razor would bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Razor's interest payment obligations and could have a material adverse effect on Razor's financial condition and results of operations. Further, Razor's indebtedness would be secured by substantially all of Razor's assets. In the event of a violation by Razor of any of its loan covenants or any other default by Razor 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 Razor'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. 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 and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Razor and may delay exploration and development activities.

Information Technology Systems and Cyber-Security

Razor 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. Razor 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, Razor 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 Razor's business activities or competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on Razor's performance and earnings, as well as on Razor's reputation. Razor 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. 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 Razor'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.

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 Razor 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 Razor 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.

Dilution

Razor 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. 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 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.

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 energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. 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.

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.

Forward-Looking Information May Prove to be Inaccurate

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

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. Subsequent to the special cash dividend, Razor declared a monthly cash dividend of $0.0125 per Common Share starting in October 2018.

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

Date paid	Amount per Common Share
October 5, 2018	$0.1650
October 31, 2018	$0.0125
November 30, 2018	$0.0125
December 31, 2018	$0.0125
Total	$0.2025

Cash Dividend Policy

It is the Company's intention to pay monthly cash dividends to Shareholders of record as of each dividend record date, currently established by the Company to be on or about the 15 day of each calendar month, with the corresponding dividend payment date generally on the last business day of each calendar month.

In determining the level of dividends to be declared, the Board takes into consideration such factors as current and expected future levels of free cash flow, capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors. Although the Company intends to continue to pay regular monthly dividends to Shareholders, dividends are not guaranteed and are issued at the discretion of the Board.

The Board intends to review this policy on a quarterly basis. Depending on factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and the Company's management team, the Board may change this policy following any such quarterly review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends being reduced or suspended entirely.

DESCRIPTION OF SHARE CAPITAL

The Company is authorized to issue an unlimited number of Common Shares without nominal or par value. As of December 31, 2018, an aggregate of 15,188,834 Common Shares were issued and outstanding. As at the date hereof, there are 15,188,834 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 13, 2018, Razor announced its intention to commence a Normal Course Issuer Bid (the "NCIB") to repurchase up to 772,442 of its common shares in open market transactions on the TSXV, representing 5% of the outstanding common shares at September 13, 2018. The NCIB will expire no later than September 13, 2019.

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)		
2018	**High**	**Low**	**Volume**
January	1.80	1.50	219,432
February	1.95	1.38	422,089
March	2.14	1.82	605,500
April	2.25	1.95	371,800
May	2.95	2.11	263,900
June	2.99	2.35	181,200
July	3.20	2.74	302,100
August	3.19	2.50	493,600
September	3.30	2.80	267,900
October	3.14	2.60	191,700
November	2.89	2.30	303,000
December	2.60	2.25	213,600

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.
Marc Bergevin Calgary, Alberta, Canada	Vice President, Engineering	—	Vice President, Engineering of the Company since September 2017. Prior thereto, Mr. Bergevin was Senior Engineer and South Area Manager of Cardinal Energy Ltd. from March 2015 to May 2018, and Engineering Manager at Penn West Exploration Ltd. from February 2012 to May 2014.
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.
Sanjib Gill (1)(2)(4) Calgary, Alberta, Canada	Director	February 3, 2017	Since January 2008, Mr. Gill has been a partner at the law firm of McCarthy Tétrault LLP, practicing law primarily in the areas of corporate finance, mergers and acquisitions.
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.
Vick Saxon (2)(3)(4) Calgary, Alberta, Canada	Director	February 3, 2017	Director for VZFOX Canada Group of Companies. Mr. Saxon also serves on the Board of Directors for a boutique venture capital firm and is a co-founder of V'NS Limited (an oil field equipment supply company).
Stan Smith (1)(3)(4) Calgary, Alberta, Canada	Director	February 3, 2017	Independent businessman since September 2016. Prior thereto, Mr. Smith was an Audit Partner with KPMG from 1984 to 2016.

Notes:
(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves and Environment Committee.
(4) Member of the Corporate Governance 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 5,423,719 Common Shares, representing approximately 35.71% 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.

Except as set forth below, 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.

Sanjib Gill was the Corporate Secretary of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Gill resigned as the Corporate Secretary immediately thereafter.

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. In particular, certain of the directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, provide financing to, or make equity investments in, competitors 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.

Sanjib Gill, a director of the Company, is a partner of the national law firm McCarthy Tétrault LLP, which law firm renders legal services to the Company. The Board of Directors does not believe that any of the activities undertaken by Mr. Gill or by McCarthy Tétrault LLP interfere, or could be perceived to interfere, in any material way, with his ability to act with a view to the best interests of Razor.

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)	2018	2017
Audit fees [1]	242,525	98,100
Audit-related fees [2]	73,575	124,260
Tax fees [3]	6,815	30,090
All other fees [4]	—	—
	322,915	252,450

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". For 2018.

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 (the "**Action**") 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.

All parties have now produced their documents and questioning was commenced. Questioning of Razor's witnesses took place in February 2019. Questioning of the remaining Defendants and of the Plaintiff's took place in March 2019. Undertaking replies and questioning on such replies remain outstanding

The Company is of the view that the claim is without merit, that the damages claimed by the Plaintiffs are excessive and grossly exaggerated and that an injunction is unlikely to be granted to prohibit the acquisition of the specified assets. Also see "*Risk Factors - Legal Proceedings*".

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, 1,239,669 Common Shares representing approximately 8.16% 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, 2018, 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, 2018.

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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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, 2018, 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:

			Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	December 31, 2018	Canada				
Total			**Nil**	**256,587**	**Nil**	**256,587**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our 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, 2018)".

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, 2019

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

____

Liam O'Brien, P.Eng.
Petroleum Engineer

Original Signed by Gary R. Finnis, P.Eng.

____

Gary R. Finnis, P.Eng.
Senior Manager, Engineering

Original Signed by Alec Kovaltchouk, P.Geo.
on behalf of Brian G. Trieber, P.L.(Geol.)

____

Brian G. Trieber, P.L.(Geol.)
Senior Technologist

Original Signed by Alec Kovaltchouk, P.Geo.

____

Alec Kovaltchouk, P.Geo.
VP, Geoscience

Original Signed by Cameron P. Six, P.Eng.

____

Cameron P. Six, P.Eng.
President and CEO

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, 2018.

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.

Doug Bailey
President, Chief Executive Officer and Director

Frank Muller
Senior Vice President, Chief Operating Officer and Director

Vick Saxon
Director and Chair of Reserves and Environment Committee

Sonny Mottahed
Director

Dated March 28, 2019