ROK RESOURCES INC.

ANNUAL INFORMATION FORM

for the year ended December 31, 2021

December 5, 2022

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ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	MMBTU or Mmbtu	million British Thermal Units
Bbls/d or bbls/d	barrels per day	Bcf or bcf	billion cubic feet
BOPD or bopd	barrels of oil per day	GJ	Gigajoule
NGLs	natural gas liquids		

Other

API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE or boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas. *Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*
BOE/D, boe/d or boepd	barrel of oil equivalent per day

In this Annual Information Form, references to “dollars” and “$” are to the currency of Canada, unless otherwise indicated.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "project", "believe", "intend", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information. 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. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. More particularly and without limitation, this Annual Information Form contains forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties or any properties in which the Corporation has an interest;
- the Corporation's strategy, plans and objectives;
- oil, NGLs and natural gas production levels and expectations of future production rates, volumes and product mixes;
- the size of the oil, NGLs and natural gas reserves and anticipated future cash flows from such reserves;
- projections of market prices, costs and exchange and inflation rates;
- supply and demand for oil and natural gas;
- the impact of seasonal factors on the Corporation;
- expectations regarding the ability to raise capital and to add reserves through acquisitions and development;
- expectations regarding acquisitions and drilling activity;
- future funds from operations;
- capital programs;
- income tax estimates and the Corporation's tax horizon;
- the impact of renegotiation or termination of contracts;
- debt levels;
- expectations regarding environmental obligations and the impact of environmental laws and regulations on the Corporation;
- future royalty rates;
- future depletion, depreciation and accretion rates; and
- the anticipated impact on the Corporation of the factors discussed under the heading "*Industry Conditions*".

The forward-looking statements and information contained in this Annual Information Form are based on certain key expectations and assumptions made by the Corporation, including but not limited to:

- prevailing commodity prices, exchange rates and weather conditions;
- applicable royalty rates, tax laws and environmental regulation;
- government regulation in the area of production curtailment;
- general economic and financial market conditions;
- future well production rates;
- the performance of existing wells;
- the success of drilling new wells in which the Corporation has an interest;
- the size of the oil, natural gas and NGL reserves in which the Corporation has an interest and the recoverability of such reserves;

- future operating costs and future cash flow;
- the Corporation's future debt levels;
- the timing and amount of capital expenditures;
- the availability of capital to undertake planned activities; and
- the availability and cost of labour, services and equipment.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks including, but not limited to:

- the impact of the COVID-19 pandemic;
- whether the Corporation can continue as a going concern;
- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- uncertainty of estimates and projections relating to production rates, oil and natural gas reserves, costs and expenses;
- liabilities inherent in oil and natural gas operations;
- failure to obtain industry partner or other third party consents and approvals, when required;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- the inability to access sufficient capital from internal and external sources;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions, dispositions and exploration and development activities, or the failure to realize the anticipated benefits of the same;
- geological, technical, drilling, completion and processing problems;
- the outcome of litigation or regulatory proceedings brought against the Corporation or other disputes involving the Corporation;
- cyber-security issues;
- fluctuations in the cost of borrowing;
- the marketability of production and demand for the Corporation's oil, NGLs and natural gas interests;
- the inability to access markets;
- changes in legislation, including changes in tax laws, incentive programs relating to the oil and gas industry, royalty and environmental legislation.
- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures;
- uncertainty of estimates and projections relating to, marketing and transportation, environmental risks, competition, and changes in tax, royalty and environmental legislation; and
- the other factors discussed under the heading *Risk Factors*.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing list of factors and risks is not exhaustive. The forward-looking statements and information contained in this Annual Information Form are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

ROK RESOURCES INC.

General

On April 6, 2010, Cap-Link Ventures Ltd. changed its name to Petrodorado Energy Ltd. (the "**Corporation**" or the "**Company**") and amended its articles under section 179 of the CBCA accordingly. On November 27, 2014, the Corporation amended its articles to consolidate its outstanding Common Shares on the basis of one post-consolidation share for every ten pre-consolidation shares. Subsequently, on September 13, 2016, the Corporation amended its articles to consolidate its outstanding Common Shares on the basis of one post-consolidation share for every five pre-consolidation shares. Therefore, share numbers referenced herein prior to November 27, 2014 are to shares existing prior to the share consolidation effective on such date, share numbers referenced after November 27, 2014 through September 13, 2016 are to shares existing prior to the share consolidation effective on September 13, 2016, and share numbers referenced after September 13, 2016 are to shares existing subsequent to both aforementioned share consolidations.

On April 4, 2016, the Corporation filed articles of amendment which created a new class of common shares and a class of preferred shares and effected an exchange of the existing Common Shares for new class B common shares ("**Class B Shares**") and preferred shares ("**Preferred Shares**") on the basis of one Class B Share and one Preferred Share for every Common Share outstanding (hereinafter referred to as the "**Share Reorganization**"). The Preferred Shares were redeemed immediately in exchange for a special distribution of cash by way of a return of capital to the shareholders of the Corporation in an amount of $0.42 per share (the "**Return of Capital**") as further described further below. The Class B Shares are identical in all respects to the Common Shares, save for the fact that all Class B Shares have two votes per share at any shareholders meeting. As a result of the Share Reorganization, there are no longer any Common Shares or Preferred Shares issued and outstanding and the only class of shares in the capital of the Corporation outstanding are Class B Shares.

On January 1, 2020, the Corporation filed articles of amalgamation under the CBCA whereby it amalgamated with its wholly owned subsidiary, ROK Resources Inc. and the amalgamated company continued under the name "ROK Resources Inc.".

Head Office and Registered Office

The Corporation has head offices in both Alberta and Saskatchewan. The Corporation's Saskatchewan head office and registered office is located at 1911 Broad Street, Regina, Saskatchewan, S4P 1Y1 and the Corporation's Alberta head office and registered office is located at Suite 750, 250 5th Street SW, Calgary, Alberta, T2P 0R4.

Stock Exchange and Reporting Issuer Status

The Corporation's Class B Shares are listed and publicly traded on the TSX Venture Exchange under the symbol "ROK". The Corporation is a reporting issuer in each of the provinces of Alberta, Saskatchewan, British Columbia and Ontario.

Intercorporate Relationships

As of the year ended December 31, 2021, the Corporation did not have any subsidiaries.

DEVELOPMENT OF THE BUSINESS

General

The Corporation is an independent oil and gas company currently operating primarily in Saskatchewan and Alberta. In recent years, the Corporation has established its oil and gas operations in the region of Southeast Saskatchewan through the acquisition of land leases and strategic acquisitions with prospective mineral rights and developed production assets. In March of 2022, the Corporation acquired assets primarily in Alberta and Saskatchewan which dramatically changed the nature of the Corporation's business. This acquisition is described in more detail below and in certain documents incorporated by reference herein.

Three-Year History

Significant developments of the Corporation over the last three completed financial years are as set forth below:

Year ended December 31, 2018

In March 2018, the Corporation mutually agreed to terminate a proposed amalgamation agreement with Western Atlas Resources Inc., pursuant to which the Corporation made a payment of $250,000 to Western Atlas Resources Inc. ("**WAR**"), with no further commitments or responsibilities existing between the parties thereafter. Other than the aborted transaction with WAR, the Corporation was largely dormant in 2018 and was seeking a transaction to commence active operations and satisfy the requirements of the TSX Venture Exchange to maintain the listing of the Common Shares.

Year ended December 31, 2019

In November 2019, the Corporation completed the acquisition of ROK Resources Inc., a private Saskatchewan oil and gas company, pursuant to which the Corporation acquired all of the issued and outstanding shares of ROK Resources Inc. Under the terms of the transaction, former ROK Resources Inc. shareholders were issued an aggregate of 20,000,000 Class B Shares of the Corporation as consideration valued at $1,100,000. Upon completion of the transaction, the current business of ROK Resources Inc. became the primary business of the Corporation. By way of this transaction, the Corporation acquired interests in certain undeveloped land located in Southeast Saskatchewan to conduct petroleum and natural gas exploratory work.

Year ended December 31, 2020

In June 2020, the Corporation closed the acquisition of certain producing petroleum and natural gas properties located within the Glen Ewen area of Southeast Saskatchewan, targeting the Midale and Frobisher formations (the "**Glen Ewen Purchase Agreement**"). The acquired assets included associated facilities and undeveloped land directly adjacent to the Corporation’s existing land base within the project area, as well as associated liabilities relating to future abandonment obligations on wells and facility sites. This contiguous area allows for cost effective development of the Corporation’s previously undeveloped lands utilizing existing processing capacity, water disposal~~s~~ and pipeline infrastructure. The acquisition package contained 27 suspended wells and 11 inactive facility sites.

As part of the acquisition, the Corporation entered into two gas purchase agreements with Steel Reef Infrastructure (“**Steel Reef Gas Handling Agreement- 5-14-3-1 Battery**” and “**Steel Reef Gas Handling Agreement- 9-23-2-1 Battery**”, respectively).

Year ended December 31, 2021

In February 2021, the Corporation acquired a non-operated working interest in producing and non-producing oil and gas assets, along with an interest in a multi-well facility in Southeastern Saskatchewan (the “**Carnduff Purchase Agreement**”). Total consideration for the acquisition was the assumption of all liabilities associated with the acquired assets and an overriding royalty. Estimated future abandonment and reclamation obligations for these acquired assets was approximately $422,000.

In April 2021, the Corporation closed a transaction to acquire certain producing oil and gas assets in Southeastern Saskatchewan for total consideration of $1,500,000 in cash and 2,000,000 Class B Shares of the Corporation (the “**Florence Non-Operated Purchase Agreement**”). The acquisition property is located within the Corporation’s core operating area in Southeast Saskatchewan, targeting the Midale and Frobisher formations.

In May 2021, the Corporation closed a transaction to acquire certain producing oil and gas assets in Southeastern Saskatchewan (the “**Florence Operated Purchase Agreement**”). Total consideration for the acquisition was $2,500,000 in cash and 2,250,000 Class B Shares of the Corporation. The acquisition property is located within the Corporation’s core operating area in Southeast Saskatchewan, targeting the Midale and Frobisher formations. The acquired asset also includes a multi-well facility and approximately 2,500 gross acres of prospective land in proximity to the Corporation’s existing land base. As part of the acquisition the Corporation entered into a gas purchase agreement with Steel Reef Infrastructure (“**Steel Reef Gas Handling Agreement- 1-10-2-1 Battery**”).

Further, the Corporation entered into a Farmout Agreement to acquire the rights to earn certain undeveloped oil and gas assets in Southeastern Saskatchewan (the “**Carievale Farmout Agreement**”). The Corporation was to participate in the drilling, completion and equipping of two earning wells, paying 70% of the costs to earn a 35% working interest in the two earning wells, plus a 35% working interest in approximately 2,900 gross acres of prospective undeveloped lands. Prior to March 31, 2022, the Corporation had the option to purchase up to a 50% interest in the undeveloped oil and gas assets, which includes two producing oil and gas wells.

On June 3, 2021, the Corporation announced that it had completed its first closing of $2,600,000 consisting of senior secured notes of the Corporation (“**Notes**”), with each Note consisting of a principal amount of $1,000 and with interest payable thereon at a rate of 14% per annum and with a term of three years from the date of issuance thereof (the “**Note Financing**”), but with the ability of the Corporation to fully repay the Notes at no penalty after two years from the date of issuance, or the Noteholders can demand repayment after two years from the date of issuance. Payments of interest only will be made during the first year of the term of the Notes and blended payments of interest and principal will be made during the second and third year of the term of the Notes. The Notes are secured by all of the assets of the Company and are senior to all other indebtedness of the Company. In addition, 500 Common Share purchase warrants (each a "**Note Warrant**") were issued to participants in the Note Financing for each $1,000 principal amount of Notes purchased, with each Note Warrant being exercisable for one Common Share at an exercise price of $0.35 per Note Warrant for a period of 2 years. The Note Financing was non-brokered. On June 23, 2021, the Corporation announced it had completed a second closing of $900,000 of Notes, bringing the total closed to date to $3,500,000 of the targeted $4,000,000 total. The final $500,000 was issued in July of 2021 bringing the total raised to $4 million. All of the Notes were either paid out or converted into Units pursuant to the Bought Public Offering in March of 2022 (see below for further particulars regarding same).

On July 21, 2021, the Corporation announced that the Board of Directors had awarded a total of 4,150,000 options to directors, officers and consultants of the Corporation. The options are exercisable into common shares in the capital of the Corporation at an exercise price of $0.28 per share. The options vest as to one third immediately with an additional one third vesting on the first anniversary of the date of grant with the remainder vesting on the second anniversary of the date of grant. The expiry for all options is July 21, 2026.

On July 23, 2021, the Corporation entered into an exploration management agreement with Hub City Minerals Corp. wherein the Corporation was issued, for nil consideration, a 25% carried interest in a private entity named Hub City Lithium Corp. (the "**Exploration Management Agreement**") which holds Subsurface Crown Mineral Dispositions in Saskatchewan (the "**Hub City Mineral Dispositions**") to be explored for potential lithium resource prospects.

On September 29, 2021, the Corporation announced the completion of a multi-layer perforation and swab test of a vertical wellbore strategically located on one of the Hub City Mineral Dispositions (the "**Lithium Test**"). The Corporation engaged two independent laboratories to analyze multiple zones of interest and measure lithium concentrations present in the formation brine. Within these zones, the targeted intervals returned lithium concentrations up to 96.3 mg/l, which exceeded the Corporation's target of 74.6 mg/l. For additional information respecting the Lithium Test, see the material change report of the Corporation, dated September 29, 2021 on SEDAR.

Events subsequent to December 31, 2021

FCL Acquisition

On February 3 and 4, 2022, the Corporation announced that it had entered into an arms-length definitive agreement (the "**Acquisition Agreement**") to acquire certain oil & gas assets (the "**Assets**"), primarily in Saskatchewan and Alberta, from Federated Co-operatives Limited and its wholly owned subsidiary 2214896 Alberta Ltd. (collectively, "**FCL**"), for total consideration of approximately $72 million ("**Transaction Value**" or "**TV**"), before closing adjustments (the "**Acquisition**").

Total consideration paid for the Acquisition was approximately $72 million ("**Transaction Value**" or "**TV**"), prior to realizing a downward purchase price adjustment of $9.6 million to account for, among other things, the November 1, 2021 effective date of the Acquisition, and was funded through a combination of proceeds from the previously announced Bought Public Offering (as defined herein) and the previously announced Senior Loan Facility (as defined herein), details of which can be found below. Details of the Senior Loan Facility and Bought Public Offering are provided below.

The Acquisition, the agreement of which was formally executed on February 3, 2022, has an effective date of November 1, 2021 and closed on March 7, 2022, was subject to certain customary conditions and regulatory and other approvals, including all necessary approvals of the TSX Venture Exchange (the "**Exchange**") all of which were eventually obtained.

Bought Public Offering

In connection with the Acquisition, ROK entered into an agreement (the "**Underwriting Agreement**") with Echelon Capital Markets ("**Echelon**") pursuant to which Echelon and a syndicate of underwriters (the "**Underwriters**") agreed to purchase 55,555,600 Subscription Receipts (as defined herein) from the Corporation at a price of $0.18 per Subscription Receipt and offer them to the public by way of a short form prospectus for total gross proceeds of approximately $10 million (the "**Bought Public Offering**").

On February 4, 2022, the Corporation announced that it had amended the terms of its previously announced offering of Subscription Receipts (as defined herein), subject to Exchange approval and any conditions related thereto. Under the amended terms of the Bought Public Offering, the Underwriters agreed to purchase 83,334,000 Subscription Receipts (the "**Subscription Receipts**") from the treasury of the Corporation, at a price of $0.18 per Subscription Receipt (the "**Issue Price**") and offer them to the public by way of short-form prospectus for total gross proceeds of $15,000,120.

Each Subscription Receipt entitled the holder thereof to receive, upon the satisfaction of certain conditions, including the completion of the Acquisition, and without payment of additional consideration or further action, one unit (a "**Unit**"), consisting of one Common Share and one Common Share purchase warrant (a "**Warrant**" and collectively the "**Warrants**"). Each Warrant entitles the holder thereof to acquire one additional Common Share at an exercise price of $0.25 for a period of 36 months from the closing date of the Bought Public Offering.

The Corporation granted the Underwriters an option to purchase up to an additional 15% of the Subscription Receipts at the Issue Price (the "**Over-Allotment Option**"). The Over-Allotment Option could be exercised in whole or in part to purchase Subscription Receipts as determined by the Underwriters upon written notice to the Corporation at any time up to 30 days following the closing date of the Bought Public Offering. The Over-Allotment Option was exercised in full by the Underwriters in connection with the closing of the Bought Public Offering. As a result, the Corporation realized total gross proceeds of $17.3 million from the Bought Public Offering, whereby 95,834,100 Units were issued.

The Corporation used the net proceeds from the Bought Public Offering to fund the consideration for the Acquisition, in addition to transaction costs and other general corporate purposes. No Units were issued to FCL as described above as the amounts raised from the Bought Public Offering and the Senior Loan Facility (as defined below) were adequate to satisfy the total consideration for the Acquisition.

Senior Loan Facility

In connection with the Acquisition, ROK announced that it had entered into a commitment letter (the "**Commitment Letter**") with respect to a senior secured loan facility with Anvil Channel Energy Solutions ("**ACES**") for an aggregate principal amount of $65 million (the "**Senior Loan Facility**"). The Senior Loan Facility bears interest at a rate of US prime + 8.00% and will amortize over a four (4) year period (the "**Term**"). Under the terms of the Senior Loan Facility, the Corporation also granted an overriding royalty to ACES Canada SPV II ULC ("**ACES Canada**") on the future oil and natural gas production from the existing oil and gas assets of the Corporation. The overriding royalty will be 2.5% of oil and natural gas production until the maturity date of the loan facility, and 1.5% thereafter.

In connection with the Acquisition and the Senior Loan Facility, the Corporation converted $2.8 million principal amount of its existing senior secured notes (the "**Senior Secured Notes**") into equity on the same terms as the Bought Public Offering ("**Senior Note Conversion**"). The remaining Senior Secured Notes were fully repurchased by the Corporation, pursuant to the terms of the Senior Secured Notes. The Units issued to the former holders of Senior Secured Notes were subject to a four month and a day hold period, expiring on July 8, 2022. In addition $0.5 million, plus a 3% origination fee, was repaid to certain management members of the Corporation which was used to contribute to the $1.0 million deposit on Transaction Value under the term of the Acquisition. A copy of the Senior Loan Facility is available on the Corporation's SEDAR profile at www.sedar.com.

Other Developments Subsequent to December 31, 2021

On March 25, 2022, the Corporation announced that the Board of Directors had awarded a total of 10,760,000 options to directors, officers, employees and consultants of the Corporation. The options are exercisable into Common Shares at an exercise price of $0.25 per share. The options vest as to one third immediately with an additional one third vesting on the first anniversary of the date of grant with the remainder vesting on the second anniversary of the date of grant. The expiry for all options is March 25, 2027.

On August 31, 2022, the Corporation announced that the Board of Directors awarded a total of 1,550,000 options. The options were granted to certain employees hired in the second quarter of 2022 and investment relations consultants of the Corporation, specifically Phil Heinrich ("**Heinrich**") and Adelaide Capital Markets Inc. ("**Adelaide**"). The options are exercisable into common shares in the capital of the Corporation at an exercise price of $0.30 per share. The options vest as to one third immediately with an additional one third vesting on the first anniversary of the date of grant with the remainder vesting on the second anniversary of the date of grant, with the exception of the options granted to investor relations consultants, which vest as to one third on the six month anniversary of the date of grant, with an additional one third vesting on the first anniversary of the date of grant with the remainder vesting on the second anniversary of the date of grant. The expiry for all options is August 31, 2027.

On October 31, 2022, the Corporation announced the appointment of an additional director, being Thomas MacInnis. In connection with his appointment, Mr. MacInnis was issued a total of 800,000 stock options with an exercise price of $0.35, vesting as to one third immediately, one third in the first anniversary date of the date of grant and the final one third on the second anniversary of the date of grant and expiring five years from the date of issuance.

Significant Acquisitions

The Corporation did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. The Corporation did complete a significant acquisition in March of 2022, which is more particularly described in the documents incorporated by reference herein.

DOCUMENTS INCORPORATED BY REFERENCE

Information has been incorporated by reference in this AIF from documents filed with securities commissions or similar regulatory authorities in each of the provinces of British Columbia, Saskatchewan, Alberta and Ontario. Except to the extent that their contents are modified or superseded by a statement contained in this AIF or in any other subsequently filed document that is also incorporated by reference in this AIF, the following documents of the Corporation filed with the securities commissions or similar regulatory authorities in each of the provinces and territories of Canada are specifically incorporated by reference into, and form an integral part of, this AIF:

(a) the business acquisition report filed on March 23, 2022 with respect to the Acquisition; and

(b) Form 51-101F1, 51-101F2 and 51-101F3 filed by the Corporation on April 29, 2022 with respect to the Corporation's oil and gas reserves.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of the Corporation at their offices c/o EnerNext Counsel, Suite 1620, 444 - 5th Avenue S.W., Calgary, Alberta T2P 2T8, telephone 403-971-9104, and are also available electronically at www.sedar.com.

Notwithstanding anything herein to the contrary, any statement contained in this AIF or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded, for the purposes of this AIF, to the extent that a statement contained herein or in any other subsequently filed document which also is, or is deemed to be, incorporated by reference herein modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document or statement which it modifies or supersedes. The making of such a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this AIF.

DESCRIPTION OF THE BUSINESS

Corporate Strategy

The Corporation's strategic priorities are to:

- identify and carry out strategic transactions in the best interest of the shareholders of the public Corporation;
- control costs through efficient management of operations;
- focus on controlling debt and managing capital expenditures effectively;
- maintain a strong focus on employee, contractor and community health and safety; and
- manage environmental and social performance to minimize negative ecological impacts and ensure continued stakeholder support.

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

Specialized Skill and Knowledge

All aspects of the Corporation's business require specialized skills and knowledge. Much of the necessary specialized skills and knowledge required by the Corporation as an oil and gas exploration and production company are available from its management team and Board of Directors. To the extent additional specialized skills and knowledge are required, the Corporation retains outside consultants.

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. The Corporation 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. Competitive factors in the distribution and marketing of oil and natural gas include price, and methods and reliability of delivery. The Corporation's competitors include resource companies which have greater financial resources, staff and facilities than those of the Corporation. The Corporation 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 below under the heading "*Risk Factors – Competition*".

Components

Any raw materials the Corporation requires to carry on its business are readily available through normal supply or business contracting channels.

Cycles

The Corporation's business may be cyclical as the exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. The level of activity in the Canadian oil and natural gas industry, and accordingly the Corporation's business, is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to decline in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation. The Corporation does not expect to be affected by seasonal weather patterns in a manner disproportionate to that of its peers in its area of operations. See below under the heading "*Risk Factors – Seasonality and Extreme Weather Conditions*".

Economic Dependence

The Corporation's business is not substantially dependent on any contract such as a contract to sell a major part of its products or services or to purchase the major part of its requirements for goods, services or raw materials, or on any franchise or licence or other agreement to use a patent, formula, trade secret, process or trade name upon which its business depends.

Changes to Contracts

Other than disclosed herein, the Corporation does not anticipate that it will be affected in the current financial year by renegotiation or termination of contracts or sub-contracts that could materially affect the Corporation's business plan.

Environmental Protection

Environmental requirements are being adhered to and monitored on an ongoing basis. The Corporation's properties are subject to stringent laws and regulations governing environmental quality. Such laws and regulations can increase the cost of planning, designing, installing and operating facilities on any properties in which the Corporation has an interest. 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, all of which might have a significant negative impact on earnings and overall competitiveness. See below under the headings "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*". The Corporation is required to abandon, retire and reclaim wells and well sites in compliance with applicable environmental and regulations. As of December 31, 2021, the Corporation has recorded an uninflated and undiscounted decommissioning obligation of $3,900,000. At September 30, 2022, the total estimated amount to settle the Corporation's decommissioning obligation on an uninflated and undiscounted basis was approximately $57,100,000. The Corporation is not aware of any environmental protection requirement, except as may be disclosed elsewhere in this Annual Information Form, that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its area of operations.

Employees

The Corporation primarily relies upon consultants to carry on many of its activities and, in particular, to supervise work programs on its properties. The Corporation faces competition for qualified personnel from numerous industry sources and there can be no assurance that the Corporation will be able to attract and retain qualified personnel on acceptable terms. See " *Risk Factors – Reliance on Key Employees*" in this AIF. As at December 31, 2021, ROK had 6 employees. As at the date hereof, ROK has 19 employees.

Foreign Operations

All of the Corporation's properties are located in Saskatchewan and Alberta, Canada. The Corporation does not have any operations outside of Canada.

Re-organizations

In a previous fiscal year, the Corporation undertook a reorganization pursuant to the Share Reorganization, as otherwise described herein. The Corporation has not undertaken any other re-organizations in the previous three fiscal years.

Social or Environmental Policies

ROK maintains a safe and environmentally responsible workplace while soliciting and taking into consideration input from neighbours, communities and other stakeholders in regard to protecting people and the environment. The Corporation remains committed to protecting shareholder value by better understanding, disclosing, and managing environmental, health, safety and sustainability.

ROK possesses an interest in the Weyburn carbon capture, utilisation and storage ("**CCUS**") unit operated by Whitecap Resources Inc. (WCP:TSX). CCUS reinjects carbon into deep geological formations which normally would be emitted into the air allowing for enhanced oil recovery, while allowing the injected carbon to remain deeply buried underground. ROK's ownership in the Weyburn CCUS unit allows the Corporation to offset the bulk of its greenhouse gas ("**GHG**") emissions.

Price Risk Management

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

(a) world market forces, including the ability of the Organization of the Petroleum Exporting Countries ("**OPEC**") to set and maintain production levels and prices for crude oil;
(b) political conditions, including the risk of hostilities in the Middle East, Eastern Europe and other regions throughout the world;
(c) increases or decreases in crude oil quality and market differentials;
(d) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;
(e) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
(f) global and domestic economic and weather conditions;

(g) price and availability of alternative fuels; and
(h) the effect of energy conservation measures and government regulations.

Revenue Sources

For the year ended December 31, 2021, ROK had total revenue from its properties of approximately $3.4 million.

PETROLEUM AND NATURAL GAS PROPERTIES

At present, ROK has beneficial interests either in the form of participation interests or royalty interests in various properties, all of which are described in the Corporation's National Instrument 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information*, prepared as at December 31, 2021 and as are further described in the Corporation's most recently filed Management's Discussion and Analysis for its most recently completed fiscal period.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The information contained in the Corporation's National Instrument 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information*, prepared as at December 31, 2021, and Form 51-101F3 *Report of Management and Directors on Oil and Gas Disclosure*, are each filed under the Corporation's profile at www.sedar.com and are incorporated by reference into this AIF.

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, municipality of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows, as of December 5, 2022:

Name and Municipality of Residence	Office(4)	Principal Occupation	Director Since(5) and Shares currently held, directly or indirectly
Cameron Taylor(1)(2) Wolseley, SK Canada	Chairman of the Board of Directors, Chief Executive Officer	Mr. Taylor is a geoscientist with over 30 years of experience in oil & gas exploration and development. Since graduating with a BSc. in Geophysics in 1988, he has worked the Williston Basin, Foothills, deep Devonian and heavy oil exploration within Canada. From November 2004 to the present, Mr. Taylor has served as a director of Pan Orient Energy, an international oil and gas exploration company with activities in Thailand, Indonesia and Canada. From September 2015 to the present, Mr. Taylor has served as a director of Burgess Creek Exploration, a private oil company with operations focused in SE Saskatchewan. Mr. Taylor served as President and CEO of Villanova 4 Oil Corp. from April 2013 to October 2014, Villanova Oil Corp. from May 2010 to April 2013 and Villanova Resources Inc. from January 2009 to May 2010. All three were private oil companies with operations focused in SE Saskatchewan.	November 28, 2019 10,108,410

Name and Municipality of Residence	Office[4]	Principal Occupation	Director Since[5] and Shares currently held, directly or indirectly
Lynn Chapman Calgary, Alberta Canada	Chief Financial Officer	Mr. Chapman was appointed Chief Financial Officer of the Corporation on January 28, 2016. Prior thereto, Mr. Chapman was the controller of the Corporation from January 2012 to January 2016, and manager of financial reporting from September 2011 to January 2012. Prior thereto, Mr. Chapman worked for KPMG LLP Calgary from January 2008 to September 2011. Mr. Chapman has a Bachelor of Business Administration from Mount Royal College (now Mount Royal University) and is a member of the Canadian Institute of Chartered Accountants. Mr. Chapman has over 12 years experience in international business with disciplines in finance, accounting and financial reporting under IFRS.	N/A 270,000
Kent McDougall[1][3] Calgary, Alberta Canada	Director	Mr. McDougall has over 35 years of experience in oil and gas marketing and commercial arrangements within the oil and gas business. Mr. McDougall is currently an owner and Chief Commercial Officer of Torq Energy Logistics Ltd., which owns midstream infrastructure and provides marketing and transportation to customers across Western Canada. From August 2011 to September 2014, he worked at Goldman Sachs as Vice President, Energy Sales. From September 2007 to August 2011, he worked at Credit Suisse as Director, Fixed Income, Energy Trading and Marketing. Mr. McDougall holds a Bachelor of Commerce degree from the University of Calgary.	August 13, 2020 3,184,000
Jeff Chisholm[2] Bangkok, Thailand	Director	Mr. Chisholm is a geoscientist with 30 years of international development and new venture evaluations experience with Pan Orient Energy, Orion Securities, Bow Valley Energy, Canadian Occidental Petroleum (Nexen) PanCanadian Petroleum (Encana) and Niko Resources. Mr. Chisholm has been President, CEO and Director of Pan Orient Energy Corp., an oil and natural gas company since July 2005 where he has managed a debt free balance sheet and returned significant capital to his shareholders.	August 13, 2020 4,336,922
Jared Lukomski Regina, Saskatchewan Canada	Senior Vice-President, Land and Business Development	Mr. Lukomski was appointed Senior Vice-President, Land and Business Development on November 28, 2019. Mr. Lukomski was the Vice-President, Land with Villanova 4 Oil Corp from January 2008 to July 2018. Prior to joining the Villanova Group, Jared was employed by Conexus Credit Union from 2000 to 2007 where he managed a book of business in his role as a Commercial Account Manager.	N/A 7,409,001
Bryden Wright Regina, Saskatchewan Canada	Chief Operating Officer	Mr. Wright was appointed Vice-President, Engineering on November 28, 2019. Mr. Wright is the former Vice-President, Engineering of Villanova 4 Oil Corp. He has over 12 years of experience in Williston Basin oil exploration and production, specifically SE Saskatchewan conventional and unconventional oil plays. Mr. Wright holds an BSc. in Petroleum Systems Engineering and is a registered Professional Engineer with the Association of Professional Engineers and Geoscientists of Saskatchewan.	N/A 5,706,292
David Hergenhein[1][2][3] Calgary, Alberta Canada	Director	Mr. Hergenhein, an independent director, has over 16 years of public accounting and financial reporting experience, including four years with Deloitte & Touche LLP. Mr. Hergenhein is a Chartered Professional Accountant (CPA) and has provided financial management services for several international junior oil and gas exploration companies. Mr. Hergenhein holds a Bachelor of Commerce degree from the University of Calgary.	May 26, 2016 735,600

Name and Municipality of Residence	Office[4]	Principal Occupation	Director Since[5] and Shares currently held, directly or indirectly
Peter Yates[2][3] Calgary, Alberta Canada	Director, Corporate Secretary	Counsel and Owner with EnerNext Counsel, a boutique legal and advisory firm since August 2017. Previously an associate at Field LLP in the corporate/securities department from November, 2015 until August 2017. Prior thereto, Partner in the securities/corporate finance group at Dentons Canada LLP (formerly Fraser Milner Casgrain LLP) from May 2012 to October 2015. Formerly an Associate in the securities, corporate finance and mergers and acquisitions group with Heenan Blaikie LLP from 2004 to 2012.	February 6, 2015 504,999
Thomas MacInnis Calgary, Alberta	Director	Mr. MacInnis is an independent businessman, currently CEO and Director of Southern Pacific Resource Corp., and a member of the advisory committee for Lex Energy Partners Funds III, IV and V. Previously Head of Financial Markets, Energy and Head of Energy Investment Banking for National Bank Financial Markets and prior thereto Managing Director of Investment Banking for Tristone Capital Inc. Mr. MacInnis holds a Bachelor of Commerce Degree from Saint Mary's University, a diploma in Petroleum Engineering from the Southern Alberta Institute of Technology, a Masters of Business Administration from the Richard Ivey School of Business at the University of Western Ontario and holds ICD.D certification from the Canadian Institute of Corporate Directors.	October 31, 2022 3,698,500

Notes:

(1) Member of the Audit Committee of the Corporation. See “Audit Committee”.

(2) Member of the Reserves and Environmental, Health and Safety Committee of the Corporation.

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

(4) As at the date of this AIF, the directors and executive officers of the Corporation, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 35,953,724 of the Corporation’s common shares, constituting approximately 17% of the issued and outstanding common shares.

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

Orders

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

Bankruptcies

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

Mr. MacInnis was a director and the Interim Chief Executive Officer of Bellatrix Exploration Inc. ("**Bellatrix**"). On October 2, 2019, Bellatrix obtained an Initial Order under the *Companies Creditors' Arrangement Act* ("**CCAA**") from the Court of Queen's Bench of Alberta seeking a stay of proceedings and other relief provided under the CCAA (the "**CCAA Proceedings**"). On June 1, 2020, Bellatrix announced that it had completed the sale of substantially all of its assets pursuant to the CCAA Proceedings. Following full repayment of all first lien secured debt outstanding, Bellatrix exited CCAA on March 29, 2022 and Bellatrix was ultimately sold to Spartan Delta on July 7, 2022. During the period that Bellatrix was undergoing CCAA proceedings, it was also cease traded for failure to file financial statements.

Penalties and Sanctions

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

Conflicts of Interest

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

AUDIT COMMITTEE

The purpose of the Corporation's audit committee is to provide assistance to the Board in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation and its subsidiaries. It is the objective of the audit committee to maintain free and open means of communication among the Board, the independent auditors and the senior management of the Corporation. For further particulars regarding the Audit Committee and the relationship with the auditor, see the management proxy circular of the

Corporation dated November 14, 2022 (the "**Circular**"), under the heading "*Audit Committee and Relationship with Auditor*" which disclosure is incorporated by reference herein.

The full text of the audit committee's charter is attached to the Circular as Schedule "A" and forms part of this Annual Information Form.

Composition of the Audit Committee

The audit committee is comprised of David Hergenhein, Kent McDougall and Cameron Taylor. David Hergenhein is the Chairman of the audit committee. Each of the members is independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"), except for Mr. Taylor, who is the Chief Executive Officer of the Corporation. Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

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

Pre-Approval Policies and Procedures

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

External Auditor Service Fees (By Category)

Year Ended	Firm	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2020	KPMG	$35,000	NIL	$4,000	NIL
December 31, 2021	KPMG	$50,000	$40,000	$12,900	$100,000

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporation's consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, review of securities filings and statutory audits.

(2) "Audit Related Fees" include services that are traditionally performed by the auditor. These audit related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "All Other Fees" include all other non-audit services.

Exemption

The Corporation is relying on the exemption in Section 6.1 of NI 52-110.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of the Corporation consists of an unlimited number of class A common shares, an unlimited number of Class B Shares and an unlimited number of Preferred Shares, of which 209,330,484

Class B Shares were issued and outstanding as at December 5, 2022. The Corporation's articles of incorporation have been filed on SEDAR at www.sedar.com.

Class A Shares

Holders of Class A Shares are entitled to (a) one vote per Class A Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally although either class of common shares of the Corporation may be issued a dividend to the exclusion of the other class of common shares; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, share rateably in such assets of the Corporation as are available for distribution.

Class B Shares

Holders of Class B Shares are entitled to (a) two votes per Class B Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally although either class of common shares of the Corporation may be issued a dividend to the exclusion of the other class of common shares; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, share rateably in such assets of the Corporation as are available for distribution.

Preferred Shares

The Preferred Shares are non-voting, entitled to priority on the distribution of assets in the event of a dissolution of the Corporation up to the amount of the redemption price for such shares as well as any accumulated dividends to that point in time and are redeemable by the Corporation at any time and with notice to the holder thereof by way of press release and at a redemption price payable in cash**.**

Warrants

The Corporation has issued and outstanding warrants exercisable to acquire Class B Shares of the Corporation that were issued as part of particular financings carried out over time, including the Bought Public Offering. For additional information respecting the warrants, see the management's discussion and analysis for the three and nine months ended September 30, 2022 and 2021 filed by the Corporation on November 21, 2022 on SEDAR.

DIVIDENDS

Other than pursuant to the Return of Capital, the Corporation has not declared or paid any dividends on any class of securities of the Corporation. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. There are no restrictions in the Corporation's constating documents that restrict the payment of dividends to any class of securities of the Corporation. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the CBCA. Pursuant to the CBCA, after the payment of a dividend, a corporation must be able to pay its liabilities as they become due and the realizable value of the assets of the corporation must be greater than the liabilities and the legal stated capital of its outstanding securities. It is the current intention of the Corporation not to pay any dividends in the near future. See "*Risk Factors – Dividends*" in this AIF.

MARKET FOR SECURITIES

Trading Price and Volume

Common Shares

The Class B Shares have been listed and posted for trading on the TSXV under the trading symbol "ROK" since January 2, 2020. Prior to that date, the Common Shares were listed and posted for trading on the TSXV under the trading symbol "PDQ". The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSXV for the periods indicated:

	Trading Price ($)		Volume Traded
	High	Low	# of shares
2021			
January	0.21	0.18	555,600
February	0.22	0.18	924,900
March	0.26	0.19	1,818,000
April	0.21	0.18	1,017,400
May	0.21	0.18	340,200
June	0.26	0.18	945,400
July	0.30	0.25	677,900
August	0.25	0.21	759,500
September	0.30	0.20	1,571,400
October	0.30	0.23	717,400
November	0.26	0.21	877,000
December	0.24	0.18	679,400
2022			
January	0.23	0.18	390,200
February	0.31	0.19	16,045,400
March	0.35	0.21	31,116,000
April	0.33	0.24	13,236,900
May	0.28	0.20	18,752,600
June	0.35	0.22	16,895,900
July	0.29	0.22	7,769,300
August	0.38	0.27	10,963,600
September	0.37	0.28	8,822,100
October	0.46	0.31	15,735,700
November	0.55	0.43	15,577,600
December 1 - 5	0.49	0.46	589,459

Warrants

The Corporation has issued common share purchase warrants to purchase Class B Shares ("**Warrants**") pursuant to its final short form prospectus filed in connection with the Bought Public Offering which have been listed and posted for trading on the TSXV under the trading symbol "ROK.WT" since March 9, 2022. The following table sets out the price range for, and trading volume of, the Warrants as reported by the TSXV for the periods indicated:

	Trading Price ($)		Volume Traded
	High	Low	# of Warrants
2022			
March 9 - 31	0.16	0.06	7,384,183
April	0.18	0.08	2,713,220
May	0.15	0.10	1,511,900
June	0.15	0.11	1,833,900
July	0.13	0.08	1,780,048
August	0.19	0.10	6,887,067
September	0.19	0.14	3,799,670
October	0.23	0.15	4,238,283
November	0.29	0.21	6,333,601
December 1 - 5	0.27	0.26	103,500

STOCK OPTION GRANTS

As of December 31, 2021, the Corporation granted, under the Corporation's stock option plan (the "**Option Plan**"), options ("**Options**") to acquire an aggregate of 6,590,000 Common Shares, the particulars of which are set forth in the following table:

Date of Grant	Number of Common Shares Issuable on Exercise(1)	Exercise Price per Share	Date of Expiry
July 18, 2018	840,000	$0.10	July 18, 2023
December 3, 2019	1,600,000	$0.15	December 3, 2024
July 21, 2021	4,150,000	$0.28	July 21, 2026

Note:

(1) Each Option entitled the holder thereof to acquire one Common Share on the terms and conditions set forth in the Option Plan. In addition to the above, the Corporation issued a total of 12,310,000 Options in 2022, as more particularly described above under the heading "*Development of the Business – Three Year History*".

ESCROWED SECURITIES

No securities of the Corporation are currently escrowed.

INDUSTRY CONDITIONS

Those operating in the crude oil and natural gas sector are subject to extensive controls and regulations in respect of operations (including land tenure, exploration, development, production, refining and upgrading, transportation and marketing) as a result of legislation enacted by the federal government and the provincial governments of Canada in the jurisdictions where the entities have assets or operations. The crude oil and natural gas industry is also subject to agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas with respect to pricing and taxation of oil and natural gas. All current legislation and regulation is a matter of public record and the Corporation is unable to predict what additional legislation, regulation or amendments may be enacted. While it is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such regulations carefully. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in the provinces in which the Corporation operates.

Pricing and Marketing in Canada

Crude Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional markets and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale.

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGLs from Canada has not changed substantively under the new regime.

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

Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect “oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment”.

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to 20 years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. We do not directly enter into contracts to export our production outside of Canada.

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

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Western Canada has experienced growing production and a lack of new and expanded pipeline and rail infrastructure capacity over recent years. This has resulted in pressure and the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, back-up local feeder pipelines. This has contributed to Western Canada producers experiencing low commodity pricing relative to other markets in the last several years. Although pipeline expansions and optimization 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 in Western Canada and limit the ability to produce and to market product. In addition, the pro-rationing of capacity on the interprovincial pipeline systems continues to affect the ability to export oil and gas.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments.

Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such 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 through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, experienced permitting difficulties in the United States and completion of the United States portion of the pipeline replacement was delayed following the announcement that the Minnesota Pollution Control Agency would require a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals declared that the Minnesota Utilities Commission correctly granted Enbridge Inc. ("**Enbridge**") a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement and Expansion. The Minnesota Supreme Court refused to hear an appeal on this matter. After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement and Expansion's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity. The Canadian portion of the pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. 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 Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the

Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019. The Federation of British Columbia Naturalists, an environmental group that was denied standing in the December 2019 judicial review, appealed the Federal Court of Appeal's standing decision to the Supreme Court of Canada. The appeal was dismissed on March 5, 2020.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. Construction continued on the Trans Mountain Pipeline throughout 2020, however, the project was halted in December 2020 resuming in January 2021 with work commencing on the twinning of the existing 1,500 km line between Alberta to British Columbia and is expected to be in-service in third quarter of 2023.

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer-long segment of the pipeline that will cross the Canada-United States Border remains dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations. In January 2021, United States President Joe Biden signed his first executive orders, including one that canceled the Keystone XL pipeline permit. On June 9, 2021, TC Energy announced it was terminating the Keystone XL project.

The Government of Alberta has also sought to alleviate pipeline transportation constraints by pursuing different transportation modalities and creating new markets. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 barrels per day of crude oil out of the province. Following the Alberta provincial election on April 16, 2019, the new United Conservative Party ("**UCP**") Government announced that it had sold off $10.6 billion in crude-by-rail contracts to the private sector. Following two train derailments which led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits which were announced February 2020 within metropolitan areas, with further mandatory speed restrictions applying outside of metropolitan areas during winter months (November 15 to March 15). As of November 21, 2022, no permanent rules have been approved.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act* (the "**OTMA**"), which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tonnes to or from British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. The OTMA is subject to review after five years. See "*Environmental Regulation –Federal*" in these Industry Conditions.

Natural Gas

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

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (the "**NGTL System**"), which carries much of Alberta's gas production, to give priority to deliveries into storage ("**Temporary Service Protocol**"). The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion of the NGTL System was recommended for approval by the CER which was sent to the federal Cabinet for approval. Following the effects of COVID-19, the Governor in Council ("**GIC**") extended the legislative timeline for consultation with Indigenous groups which extended the decision date to no later than May 2021. On April 30, 2021 the GIC approved the issuance of the certificate of public convenience by the CER. In July 2020, the Explorers and Producers Association of Canada applied to extend the Temporary Service Protocel, which was opposed by NOVA Gas Transmission Ltd. and ultimately denied by the CER in February 2021.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline, which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**") (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. Coastal Gaslink Pipeline Ltd. obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020. On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area. The CGL Pipeline continues to experience delays with the EOA ordering a halt in construction on October 14, 2022 citing, among other things, violations of the project's environmental permit.

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service. Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for a hearing for approval of the proposed service and tolling framework. On November 26, 2021, the CER issues its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90 percent of Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from 8 to 20 years. Contract for firm service were to be awarded through an open season process put forward as part of the application.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains 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 the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The USMCA does not contain the proportionality rules of NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. 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 crude oil and natural 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. In light of the United Kingdom's departure from the European Union on January 31, 2020, CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021. The Canada-United Kingdom Trade Continuity Agreement replicates the CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and ten other countries have agreed on the 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. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

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

Land Tenure

The respective provincial governments (*i.e.*, the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (where the Crown only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude 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. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time, and other conditions are satisfied.

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

Each of the provinces of Western Canada have 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 licence. In addition, Alberta 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 new leases and licences. For leases and licenses issued subsequent to January 1, 2009, shallow rights reservation 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 industry with notice if, in the future, a decision is made to serve shallow rights reservation notices.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (*i.e.*, freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba approximately 19%, 6%, 20%, and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada (“**IOGC**”), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations. Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the “**IOGA**”) and the *Indian Oil and Gas Regulations, 1995* (the “**1995 Regulations**”). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the “**Modernized IOGA**”), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the “**2019 Regulations**”). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. We do not have any material operations on Indian reserve lands.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally, the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low, to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

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.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments, and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and is subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a 5- year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane based GHG emissions by 40 to 45 percent between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Royalty/Tax Regime for High Water-Cut Oil Wells was amended in May 2021 designed to improve water handling capabilities and extend the producing lives of wells producing large volumes of water. After a qualifying investment has been made to directly improve the water handling capabilities and extend the producing life of a high water-cut oil well, the royalty status will be assigned based upon the well's finished drilling state. Wells drilled on or after October 1, 2022 will receive a 2 percent royalty rate deduction on all future incremental high water-cut oil production.

Any changes to the royalty regime in Saskatchewan may have a material effect on ROK. See "*Risk Factors - Royalty Regimes.*"

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced from Crown Lands. Producers of oil and natural gas from Crown lands in Alberta are also required to pay a royalty on substances produced from Crown lands.

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 included 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. At this time, an Emerging Resources and Technologies Initiative was also 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 receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells 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 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 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 modern royalty framework (the "**MRF**"), the sliding scale royalty concept was maintained, but is achieved with a greater deal of simplicity. The new royalty percentage is applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells are charged a flat 5 percent royalty rate until revenues exceed a normalized well cost allowance, which is 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. The former Alberta Royalty Framework continues to apply to any wells drilled prior to January 1, 2017, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. As of January 1, 2027, older wells will become subject to the MRF.

Royalties on production from wells subject to the MRF are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the Alberta Energy Regulator ("**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Producers under the MRF, initially pay a flat rate of 5 percent of gross revenue from each well that is subject to the MRF until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5 percent and 40 percent for crude oil and pentanes and 5 percent and 36 percent for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Alberta Royalty Framework, the post-payout royalty rate under the MRF varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5 percent as the mature well's production declines. As the MRF uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low-cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance.

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.

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

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Alberta Royalty Framework range from a base rate of 0 percent to a cap of 40 percent; royalty rates for natural gas production under the Alberta Royalty Framework range from a base rate of 5 percent to a cap of 36 percent. The Alberta Royalty Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 meters deep, as well as the acid gas content of the produced gas. Under the Alberta Royalty Framework, the royalty rate applicable to NGL is a flat rate of 40 percent for pentanes and 30 percent for butanes and propane.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

On July 18, 2019, the Government of Alberta enacted the Royalty Guarantee Act to provide certainty that no major changes will be made to the current oil and gas royalty structure for a period of at least 10 years. The Royalty Guarantee Act also confirms that the transition to the MRF for wells drilled on or before December 31, 2016 will occur as planned in 2026.

Freehold and Other Types of Non-Crown Royalties

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

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

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

Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment, and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. Certain environmental protection legislation may subject ROK 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, ROK 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 June 21, 2019 Bill C-48 (the OTMA), came into force. 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. This 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.

As previously discussed in *Industry Conditions — Transportation Constraints and Market Access*, the CERA and the IAA came into force and the NEB was replaced with the CER in 2019. In addition, the Impact Assessment Agency ("**IA Agency**") replaced the Canadian Environmental Assessment Agency.

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments, including the enactment of the IAA. Pursuant to the IAA, "Designated Projects" will require an impact assessment as part of their regulatory review. The impact assessment, conducted by the IA Agency, and may be conducted by a joint review panel with other provincial governments or the CER, as needed and includes expanded criteria the review panel may consider when reviewing an application. Under the CERA, certain projects are considered Designated Projects requiring an impact assessment and those project which are subject to the CERA will undergo an integrated impact assessment, led by the IA Agency.

The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. In conducting its assessment, the IA Agency must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75 kilometers of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

As stated, the objective of the legislative changes are to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are time limits the relevant regulatory authority will have to issue its report and recommendation. Designated Projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non- designated projects will follow a similar process as under the NEB Act. The impacts of the IAA are unknown on oil and natural gas projects as few have been subject to the new regime. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has yet to be substantially tested.

On July 17, 2020, the federal government published its Strategic Assessment of Climate Change ("**SACC**") to assess the impacts of climate change in federal impact assessments conducted under the IAA. The SACC applies to Designated Projects under the IAA. Guidance for projects regulated by the CER will consider the principles and objectives of the SACC. The SACC may also apply to environmental reviews by other federal lifecycle regulators, and be used in regional assessments. ECCC has indicated it plans to review and update the SACC every 5 years. Proponents will be required to provide information about the emissions intensity of their projects, and this information will be compared to national and international projects of a similar scope and nature. A description of mitigation measures and the plan for the project to achieve net-zero emission by 2050 will also be required, as is information on the project's ability to scope with the physical impacts of climate change.

Saskatchewan

Saskatchewan's Ministry of the Economy and the Oil and Gas Conservation Board collectively regulate oil and gas activities in the province, which is primarily governed by the *Natural Resources Act* and *The Oil and Gas Conservation Act* ("**SKOGCA**").

The *Environmental Management and Protection Act* ("**EMPA**") regulates the protection of the environment in Saskatchewan, including among others the designation of environmentally impacted sites, issuance of environmental protection orders, and obligations to report releases of substances. Most importantly, the EMPA prohibits the discharge of substances causing adverse effects to the environment, and assigns responsibility for such adverse effects to a broad category of "persons responsible." This includes the person who caused or contributed to the discharge (*i.e.*, fugitive release of sour gas or flaring in excess of the permitted levels), had possession or control of the substance, as well as every owner and occupier of the land, including subsequent owners and occupiers and any person transporting the substance.

In May 2011, Saskatchewan passed changes to SKOGCA. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural aspects, including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Alberta

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* ("**ABOGCA**"). EPEA, the Water Act and the ABOGCA 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.

EPEA regulates the protection of the environment in Alberta, including among others the designation of environmentally impacted sites, issuance of environmental protection orders, and obligations to report releases of substances. EPEA provides for the prohibition on the discharge of substances which cause an adverse effect to the environment and assigns responsibility for such adverse effect to a "person responsible", which is defined broadly. This definition includes previous owners of the substance or thing, any person who had charge, management or control of the substance or thing, including the sale, handling, use, storage or disposal of the substance or thing any successor or assignee of such person.

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 AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the ABOGCA. 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.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land, and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access.

The South Saskatchewan Regional Plan ("**SSRP**") was approved by the Government of Alberta on July 23, 2014 and became effective on September 1, 2014. The SSRP is the second regional plan developed under the ALUF and covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, oil and gas companies must nonetheless minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. Freehold mineral rights will not be subject to this restriction. With the implementation of the new Alberta regulatory structure under the AER, AEP will remain responsible for development and implementation of regional plans.

However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Pursuant to several ministerial orders passed pursuant to s. 52.1(2) of the *Alberta Public Health Act* which declared a state of public health emergency in Alberta due to the COVID-19 pandemic, certain industrial environmental reporting requirements including the extension of deadlines or the suspension of reporting requirements under EPEA and the *Water Act*. The ministerial orders expired on August 14, 2020 and all environmental reporting should resume in accordance with the prescribed deadlines and requirements.

Liability Management Rating Programs

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (*i.e.*, an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities.

In *Redwater Energy Corporation (Re), 2016 ABQB 278* ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* (Alberta) and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry- funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. On January 31, 2019, the Supreme Court of Canada ruled on the appeal of Redwater in *Orphan Well Association v. Grant Thornton Limited*, 2019 SCC 5 (the "**SCC Redwater Decision**") 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.

On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater including, among other things, that it considers all licence transfer applications non-routine as it does not strictly rely on the standard license liability rating ("**LLR**") calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Alberta

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* in an urgent response to *Redwater*. In response to the SCC Redwater Decision, the AER began working on an improved liability management framework. On July 30, 2020, the Government of Alberta announced that it will introduce a new Liability Management Framework ("**LMF**") for the oil and gas industry which is intended to replace the Alberta Liability Management Program (the "**LMR Program**"). The LMF is intended to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the LMF through legislative and AER directive amendments.

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

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

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

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

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

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 008: *Licensee Life-Cycle Management*. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduces new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the LMF, the AB LLR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the LMF, each licencee will be required to meet mandatory annual spend targets for well closures and abandonments starting January 2022. The AER has set an industry-wide mandatory closure spend target for the oil and gas sector in 2023 of $700 million with a forecasted target for 2024 of $764 million.

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

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

The implementation of the LMF is still ongoing and the AER has announced that several changes are still expected to improve existing liability programs and implement the new LMF. The expectation is the LMF will replace the AB LMR Program in its entirety, however, such transition will require time as the AB LMR Program is integrated throughout the regulatory regime including Directives and legislation. Implementation of the LMF is expected to continue throughout 2022, with the gradual and phasing changes to legislative, regulatory and AER directives in order to adequately implement and integrate the LMF.

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

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The full impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and funds flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"), which was entered into in order to 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 committed to 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. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021 in Glasgow. The result of The 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

In May 2015, Canada submitted its Intended Nationally Determined Contribution to the UNFCCC Secretariat, pledging a 30 percent reduction from 2005 levels—approximately 523 Mt—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.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**") which builds on the Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3-billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. Also of relevance to the petroleum and natural gas industry, on December 21, 2021, the federal government announced that it intends to publish draft regulations that will implement a ban on the manufacture, import and sale of six categories of single-use plastics. The draft regulations are to come into force in late 2022.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Bill C-12 received royal assent on June 29, 2021 and will legally bind the federal government to a process to achieve net-zero emissions by 2050. Among other things, the legislation sets rolling five-year emissions-reduction targets (starting in 2030) and requires plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry ("**OBPS**") and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of $20/tonne of carbon dioxide equivalent emissions ("**CO2e**"). This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the stringency standards set by the federal government. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. The price is set to increase to $50/tonne of CO2e on April 1, 2022.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the Supreme Court of Canada ("**SCC**") and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in *Reference re Greenhouse Gas Pollution Pricing Act*, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada. Manitoba had also made an appeal to the Federal Court stating the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October 2021, the Federal Court rejected Manitoba's argument stating the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum federal stringency standards. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OPBS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. For so long as the provincial systems in Prince Edward Island, Alberta (under the *Technology Innovation and Emissions Reduction (TIER)* regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement set 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.

The federal government requires that GHG emissions be reported annually. On December 18, 2021, the notice published by the federal government with respect to reporting of GHGs for 2021 was published in the Canada Gazette for the 2021 reporting year. The 2021 notice builds on the notice published in 2020 which included an expanded data and methodological requirement for various sectors.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incentivize 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, Environment and Climate Change Canada ("**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. On December 18, 2020, the federal government published proposed CFS regulations, the final regulations of which are expected to be published in 2021 with the CFS regulations scheduled to come into force in December 2022.

The proposed CFS regulations take a performance-based approach to reducing GHG emissions and subsequent effects on the Corporation, its operations, obligations or the industry in which it operates. The CFS regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to gradually cut the amount of carbon in their product. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability meet requirements in a cost-effective way that works for their business. The proposed regulations also offer compliance credits to incentive industries to innovate and adopt cleaner technologies to lower their compliance costs.

ROK will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The US Environmental Protection Agency ("**EPA**") is proceeding to regulate GHGs under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Saskatchewan

In October 2016, Saskatchewan released its Climate Change White Paper, which outlined the principles of the province's approach to climate change, including a focus on both mitigation and adaptation responses to climate change. Following the release of the Climate Change White Paper, the government worked on developing its comprehensive climate change strategy, which was released in December 2017: Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy (the "**Strategy**"). The Strategy focuses on the principles of readiness and climate resilience, curbing GHG emissions, and preparing for changing conditions such as extreme weather, drought or wildfire. Saskatchewan decided not to sign on to the Framework or to adopt a carbon pricing mechanism, meaning that it will be out of compliance with federal requirements. The Strategy proposes actions in key areas, including (i) natural systems; (ii) physical infrastructure; (iii) economic sustainability; (iv) community preparedness; and (v) measuring, monitoring and reporting. Although no specific emission reduction targets are set out in the Strategy, the Saskatchewan government has indicated that it will support Canada's efforts to meet national commitments under the Paris Agreement. Prior to the release of the Strategy, Saskatchewan relied on the GoGreen Saskatchewan initiative to encourage the reduction of GHG emissions and to educate the public about climate change. Between 2008 and 2015, the Saskatchewan government estimates that it invested $60 million in GoGreen funding through public/private partnerships.

The Government of Saskatchewan announced the introduction of the Management and Reduction of Greenhouse Gases Act (the "**MRGGA**") to regulate GHG emissions in the province on May 11, 2009. The MRGGA is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018. The MRGGA establishes a framework to reduce GHG emissions by 20 percent of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full force on December 18, 2018, establishing the framework of an output-based emissions management framework. The Fuel Charge applies in Saskatchewan and the system implemented by the MRGGA currently meets the federal stringency standards for the emissions it covers and the OBPS applies for those emissions which are not covered.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: The *Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, *the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licencees of oil facilities that may generate more than 50,000 tonnes of CO_2e per year, obliging each licencee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 percent to 45 percent by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO_2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO_2e by 2030.

Under the MRGGA, the output-based performance standards apply to large industrial facilities that emit greater than 25,000 tonnes of CO_2e annually for regulated sectors, including oil and gas. Facilities that emit 10,000 - 25,000 tonnes of CO_2e annually may opt-in.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under the Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50 percent by 2030.

On October 1, 2019, Bill 147 — An Act to amend the Oil and Gas Conservation Act, was proclaimed into force that, in part, amends the Oil and Gas Conservation Act to the extent necessary to bring it into alignment with the Saskatchewan *Oil and Gas Emissions Management Regulations*. The *Oil and Gas Emissions Management Regulations* came into effect January 1st, 2019. The *Oil and Gas Emissions Management Regulations* were introduced as a made-in-Saskatchewan results-based regulation to reduce methane-based GHG emissions by 4.5 million tonnes of CO2e from 2015 levels by 2025.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020 ("**PNG036**"). Licensees in Saskatchewan must comply with the requirements for managing venting and flaring at oil and gas wells and facilities in Saskatchewan as outlined in PNG036, which replaced the previously enacted Upstream Petroleum Industry Associated Gas Conservation. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024.

Saskatchewan has also identified technology as a key driver of emission reductions, including carbon capture use and storage as well as renewable energy.

Alberta

Alberta's Climate Leadership Plan was introduced in November 2015 with the following policy objectives: (i) putting a price on GHG emissions; (ii) phasing out coal-generated electricity by 2030; (iii) having 30 percent of electricity be generated from renewable sources by 2030; (iv) capping oil sands emissions to 100 Mt per year; and (v) reducing methane emissions by 45 percent by 2025.

On January 1, 2018, the *Carbon Competitiveness Incentive Regulation* ("**CCI Regulation**") replaced the *Specified Gas Emitters Regulation*. Under the CCI Regulation, facilities were allowed to emit a certain amount of GHG, free of charge from the carbon levy in place at the time. The CCI Regulation applied to facilities that emitted 100,000 tonnes or more of GHGs in 2003, or a subsequent year. Under the CCI Regulations, a facility would receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions were above the amount freely permitted, they were required take one or more of the following actions to bring the facility into compliance: (i) make improvements at their facility to reduce emissions intensity; (ii) use emission performance credits generated at facilities that achieve more than the required reductions; (iii) purchase Alberta-based carbon offset credits; or (iv) 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 on December 14, 2016. The legislation includes certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments).

In June 2019, the Government of Alberta pivoted in its implementation of the Climate Leadership Plan and repealed the Climate Leadership Plan. The **Carbon Competitiveness Incentives Regulation** ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $40/tonne of CO2e and will increase to $50/tonne on April 1, 2022. On December 4, 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation which replaced the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020 and is currently under review by the Government of Alberta with such review expected to be completed by the end of 2022.

The TIER regulation operates differently than the former facility based CCIR, and instead applies to industrywide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10 percent as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1 percent reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Similar to the CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to the TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation as an aggregate facility. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

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

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by approximately 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act*, 2010. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. On December 2, 2021, the AER released a Request for Full Project Proposals for Carbon Sequestration Hubs ("**RFPP**"). Following significant interest in carbon capture and storage, the RFPP is intended to facilitate the issuance of rights to Alberta's pore space to proponents to enable the development and operation of carbon storage hubs.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a non-exhaustive summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities. If any of the risks described below materialize, the Corporation's business, financial condition, results of operations and the value of the Corporation's securities could be materially and adversely affected. Additional risks and uncertainties not currently known to the Corporation that we currently view as immaterial may also materially and adversely affect our business, financial condition, results of operations or value of the Corporation's securities.

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Forward-Looking Statements*".

COVID-19

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on ROK's business, including changes to the way we and our counterparties operate, and on our financial results and condition. The spread of the COVID-19 pandemic, given its severity and scale, continues to adversely affect our business to varying degrees and many of our customers and business partners and also continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. While a number of containment measures have been and continue to be gradually eased or lifted across some regions, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 have been and continue to be instituted in line with guidance of public health authorities. In addition, the emergence of the second, third and fourth waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains such as the Delta strain and the Omicron strain, has led to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures continue to impact global economic activity, including the ability to move towards recovery of the global economy and such measures also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. As the impacts of the COVID-19 pandemic continue to materialize, the prolonged effects of the disruption have had and continue to have adverse impacts on ROK's business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks.

The COVID-19 pandemic has resulted, and may continue to result, in disruptions to some of ROK's business partners, clients and customers and the way in which we conduct our business, including prolonged duration of staff working from home. These factors have impacted, and may continue to impact, our business operations and continuity of relationships with our business partners. Operational risks which may affect the Corporation or our business partners include the need to provide enhanced safety measures for employees and customers; complying with rapidly changing regulatory guidance; addressing the risks of attempted fraudulent activity and cybersecurity threat behavior; and protecting the integrity and functionality of the Corporation's systems, networks and data as a larger number of employees work remotely.

If the COVID-19 pandemic is further prolonged, including the possibility of additional subsequent waves, and introduction of new variants, or further diseases merge that give rise to similar effects, the adverse impact on the economy could deepen and result in further volatility and declines in commodity and financial markets. Moreover, it remains uncertain how the macroeconomic environment will be impacted following the COVID-19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Corporation's business and financial condition, potentially for a substantial period of time.

Credit Facilities Risks

The Corporation is required to comply with covenants under the Senior Loan Facility which may affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Senior Loan Facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Senior Loan Facility, the lenders under the Senior Loan Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Senior Loan Facility may impose operating and financial restrictions on the Corporation that could include restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has the effect of adjusting lending practices to account for end-of-life obligations that were thought to be subordinate to secured debt and will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions — Liability Management Rating Programs*".

Prices, Markets and Marketing

Prices for hydrocarbons are subject to large fluctuations in response to relatively minor changes to the demand for crude oil, NGLs and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and NGLs by rail. Numerous factors beyond ROK's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation, including:

- deliverability uncertainties related to the distance our reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities;
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas;
- political instability;
- COVID-19; and
- the availability of alternative fuel sources.

Historically, the markets for crude oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future because of market uncertainties over the supply and demand of these commodities due to COVID-19, the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East, conflicts in Eastern Europe and ongoing credit and liquidity concerns.

Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The prices received by ROK for its oil are subject to differentials against such benchmarks as WTI which can fluctuate substantially and result in ROK realizing prices substantially below such benchmarks. 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, including to international markets. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources.

The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices and may experience delays or cancellation of existing or future drilling, development or construction programs or the curtailment of production as a result of weak commodity prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects. See "Industry Conditions – Transportation Constraints and Market Access" and "Weakness in the Oil and Gas Industry" in these Risk Factors.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects. No assurance can be given that crude oil and natural gas prices will be sustained at levels which will enable the Corporation to operate profitably. ROK may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, ROK will not benefit from such increases.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, and pipeline systems. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline and railway lines. On February 19, 2019, the Government of Alberta announced it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to alleviate transportation constraints impacting Canadian oil prices. In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector. The ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in our inability to realize the full economic potential of our production, or in a reduction of the price offered for our 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 ROK'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 ROK's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the federal government and 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, the impact of the new IAA regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear as it remains relatively untested since its enactment.

Following major accidents in Lac-Megantic, Québec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

Even with gathering and processing facilities, pipeline systems and railway lines in place, the amount of oil and natural gas that can be produced and sold will be subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the transportation system or interruptions in other transportation means, such as trucking or barging activities. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, the Corporation may only be provided with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in pipeline capacity or other transportation means could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

Weakness in the Oil and Gas Industry

Market events and conditions, including COVID-19, global excess oil and natural gas supply, recent actions taken by OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, conflict between Russia and Ukraine, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Political Uncertainty*" in these Risk Factors. These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Royalty Regimes*" and "*Regulatory*" and "*Environmental*" and "*Climate Change*" in these Risk Factors. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict our cash flows from operating activities resulting in less cash flows from operating activities being available to fund our capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year-over-year basis. See "*Reserve Estimates*" in these Risk Factors. In addition to possibly resulting in a decrease in the value of our economically recoverable reserves, lower commodity prices may also result in a decrease in the value of our infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of our oil and natural gas assets on our balance sheet and the recognition of an impairment charge on our income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. See "*Additional Financing*" in these Risk Factors.

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. administration has withdrawn the United States from the Trans-Pacific Partnership ("**TPP**") and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The U.S. has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States. The political unrest associated with the transition to the new Biden administration over the past year is unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown.

In addition, NAFTA has been renegotiated and on December 10, 2019, and Canada, the U.S. and Mexico signed the USMCA which replaced NAFTA. See *"Industry Conditions — The North American Free Trade Agreement and Other Trade Agreements".* 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 unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the new U.S. administration may have 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 ROK.

In addition to the political disruption in the United States, on January 31, 2020 the United Kingdom officially withdrew from the European Union. Since the United Kingdom's departure, it remains unclear what the effects of this will be as a final deal was reached between the European Union and the United Kingdom which came into effect on December 31, 2020. 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 ROK'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 ROK securities.

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

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

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – The North American Free Trade Agreement and Other Trade Agreements*".

Changing Investor Sentiment

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

Exploration, Development and Production Risks

An investment in the Corporation is subject to a high degree of risk related to the nature of the Corporation's business and the current stage of development of the Corporation's oil and gas business that even a combination of experience, knowledge and careful evaluation may not be able to overcome. There are numerous factors which may affect the success of the Corporation's business which are beyond the Corporation's control including, among other things, local, national and international economic and political conditions.

The Corporation may be subject to growth-related risks, capacity constraints and pressure on its internal systems and controls, particularly given the current stage of its development. The Corporation's future crude oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Corporation successfully discovering and developing or acquiring new reserves or otherwise acquiring an interest therein. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. Accordingly, there can therefore be no assurance that the Corporation's business will be successful or profitable or that we will discover or acquire further commercial quantities of crude oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect funds from operations to varying degrees.

To the extent ROK is not the operator of its oil and natural gas properties, it is dependent on such operators for the timing of activities related to such properties and is largely unable to direct or control the activities of the operators. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although ROK intends to operate the majority of its properties, there is no guarantee that it will remain operator of such properties or that ROK will operate other properties it may acquire in the future.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, some of the Corporation's current or future properties may include wells that produce sour natural gas and facilities that process sour natural gas. An accidental discharge or leak of sour natural gas can be fatal or cause serious injury. The dangers associated with drilling for, producing, processing and transporting sour natural gas necessitate increased environmental, health and safety compliance costs to ROK and any accidental discharge or leak of sour natural gas could lead to significant liabilities to ROK. ROK has implemented measures to address this risk, but it is not possible for any issuer to eliminate all of the risks associated with producing, processing and transporting sour natural gas.

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

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain comprehensive insurance, including but not limited to general commercial liability, sudden and accidental pollution, control of well and property and machinery insurance in an amount that we consider consistent with standard industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Insurance*" in these Risk Factors. In either event, we could incur significant costs.

In addition, the success of ROK will be largely dependent upon the performance of its management and key employees. There is a risk that the death or departure of any member of management or any key employee of ROK could have a material adverse effect on the Corporation. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse effect on its business, operations and prospects.

Additional Financing

Our future net revenue from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. The oil and gas industry generally is capital intensive and the Corporation's participation in the industry will likely require additional financing to fund such capital expenditures. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations.

The ability of the Corporation to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Corporation. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we may, from time to time, have restricted access to capital and increased borrowing costs as periodic fluctuations in energy prices may affect lending policies of banks. An inability to raise additional financing could limit growth prospects in the short run or may even require the Corporation to dispose of its interest in properties to continue operations under circumstances of declining energy prices, disappointing exploration results or economic dislocation. In the alternative, the Corporation will be required to enter into joint venture or farm-out agreements or potentially sell the Corporation to an entity with greater resources.

If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

In addition, the Corporation may be required to fund its ongoing operations, capital expenditures or transactions to acquire assets or the shares of other Corporations through debt financing which may increase the Corporation's debt levels above industry standards.

Project Risks

We manage a variety of projects in the conduct of our business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, pressure maintenance and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;

- accidental events;
- currency fluctuations;
- regulatory changes;
- 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, we could be unable to execute projects on time, on budget, or at all.

Market Price

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our securities could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for ROK securities will be subject to market trends generally, notwithstanding the financial and operational performance of ROK, and accordingly, the price at which our securities will trade cannot be accurately predicted.

Climate Change

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 Corporation operates. In November 2018, ENvironment JEUnesse, a Québec advocacy group, applied to the Québec Superior Court to certify a class action against the Government of Canada for climate related matters. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for climate-related harms. The application was denied and ENvironment JEUnesse appealed to the Appeal Court of Québec on February 23, 2021. The appeal was dismissed on December 13, 2021. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against crude oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Public and government hostility toward the oil and gas industry could reduce demand for oil and gas and, therefore, adversely affect market prices for the Corporation's production. Existing and future laws and regulations may impose additional costs on companies operating in the oil and gas industry or significant liabilities for failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry in general.

ROK's exploration and production facilities and other operations and activities emit GHGs which may require us 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. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 5, 2016, the Government of Canada pledged to cut its GHG emissions by 30 percent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the nation-wide price on carbon emissions.

In the spring of 2021, the SCC upheld the GGPPA as constitutional. Currently the Fuel Charge applies in Alberta and Saskatchewan while the OPBS applies in partially in Saskatchewan. For so long as the provincial systems in place in Alberta and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

The perceived elevated long-term risks associated with regulatory changes or other market developments related to climate change have also impacted the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other institutional investors which promote direct engagement and dialogue with companies in their portfolios on climate change action and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to crude oil and natural gas and related infrastructure businesses and projects. The impact of such efforts may require the Corporation's management to dedicate significant time and resources to these climate change related concerns, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses and in the long-term reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs.

See "*Industry Conditions — Climate Change Regulation*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict our ability to access our properties and cause operational difficulties, including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that if subjected to a wildfire or flood could lead to significant downtime and/or damage to such assets.

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

Environmental Concerns

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that ROK may be in noncompliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose ROK to fines or penalties, third-party liabilities or to the requirement to remediate, which could be material.

The operational hazards associated with possible blowouts, accidents, oil spills, natural gas leaks, fires, or other damage to a well or a pipeline may require ROK to incur costs and delays to undertake corrective actions, could result in environmental damage or contamination or could result in serious injury or death to employees, consultants, contractors or members of the public, creating the potential for significant liability to ROK. Also, the occurrence of any such incident could damage ROK's reputation in the surrounding communities and make it more difficult for ROK to pursue its operations in those areas.

Compliance with environmental laws and regulations could materially increase ROK's costs. ROK may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, the Corporation may be required to incur significant costs to comply with future federal or provincial greenhouse gas emissions reduction requirements or other regulations, if enacted. See "*Industry Conditions — Environmental Regulation*".

The oil and natural gas industry elicits concerns about climate change, as well as general public opposition to the industry. As a result, industry participants may be subject to increased public activism, which could result in increased costs due to delays or damage.

Although ROK maintains insurance consistent with prudent industry practice, it is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, the Corporation's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to ROK.

New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". The Corporation cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Corporation for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and the value of the Corporation's securities.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur, from time to time, in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". Also see "*Liability Management*" in these Risk Factors.

In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our securities or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Liability Management Rating Programs*".

Availability and Cost of Material and Equipment

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede our exploration, development and operating activities.

Reputational Risk Associated with Our Operations

Our business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which we operate as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which we have no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact our reputation. See "*Climate Change*" in these Risk Factors. Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Damage to our reputation could result in negative investor sentiment towards us, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including us, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

Similarly, from time to time, we may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, we will not benefit from the fluctuating exchange rate.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the control of the Corporation. Geological and engineering data is used to determine the probability that a reservoir of oil and/or natural gas exists at a particular location, and whether, and to what extent, such hydrocarbons are recoverable from the reservoir. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net revenues from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

Accordingly, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net revenues. Actual future net revenues 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 future net revenue derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated future net revenue to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Dividends

Other than pursuant to the Return of Capital, the Corporation has not declared or paid any dividends on any class of securities of the Corporation and does not anticipate paying any dividends in the foreseeable future. It is not contemplated that any dividends will be paid on the Corporation's securities in the immediate future as it is anticipated that all available funds will be invested to finance the growth of the Corporation's business. The Board of the Corporation will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on the Corporation's earnings, financial position, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends and other conditions at the relevant time. Depending on these and various other factors, many of which will be beyond our control, our dividend policy may vary from time to time and, as a result, future cash dividends, if any, could be reduced or suspended entirely.

Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends, if any, may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operations. To the extent that external sources of capital, including in exchange for the issuance of additional securities, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced. The market value of the Corporation's securities may deteriorate if cash dividends are reduced or suspended.

Exploration Risks

The exploration of the properties in which the Corporation has an interest may from time to time involve a high degree of risk that no production will be obtained. The costs of seismic operations and drilling, completing and operating wells are uncertain to a degree. Cost overruns can adversely affect the economics of the properties in which the Corporation has an interest. In addition, seismic operations and drilling plans for properties in which the Corporation has an interest may be curtailed, delayed or cancelled as a result of numerous factors, including, among others, equipment failures, weather or adverse climate conditions, shortages or delays in obtaining qualified personnel, shortages or delays in the delivery of or access to equipment, necessary governmental, regulatory or other third party approvals and compliance with regulatory requirements.

Title to Properties, Investments in Properties

Although title reviews will be performed according to industry standards prior to the purchase of most crude oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation. If a defect exists in the chain of title or in our right to produce, or a legal challenge or legislative change arises, it is possible that we may lose all, or a portion of, the properties to which the title defect relates and/or our right to produce from such properties. There is no guarantee that an unforeseen defect in title, changes in laws or change in their interpretation, legal challenge or political events will not arise to defeat or impair the claim of the Corporation to properties in which it has interest which could result in a material adverse effect on the Corporation, including a reduction in revenue.

Additionally, the properties in which the Corporation has an interest, and those in which it may have an interest in the future, may be acquired from various third parties where the contractual terms for exploration and investment requirements governing our interest in each property could vary significantly from one property to the other. Accordingly, the terms and conditions that the Corporation's acquisition of property interests will be subject to cannot be accurately predicted.

Expiration of Licenses and Leases

The Corporation holds properties in the form of licenses and leases and working interests in licenses and leases. If the Corporation, or the holder of the license or lease, fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of our licenses or leases or the working interests relating to a license or lease and the associated abandonment and reclamation obligations may have a material adverse effect on our business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The contributions of the Corporation's executive management team are likely to be of central importance with the Corporation's success depending in large part on the ability of its executive management team to deal effectively with complex risks and relationships and execute the Corporation's business development plan. The members of the management team contribute to the Corporation's ability to obtain, generate and manage opportunities. The Corporation's prospects also depend upon the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans.

We compete with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals, and/or difficulties in maintaining labour productivity that may adversely affect our profitability.

There can be no assurance that the Corporation's present key personnel and directors will remain with the Corporation or that the Corporation will be able to retain its service providers. We do not have any key personnel insurance in effect. The departure of any such key person, director or service provider may materially affect the Corporation's business, financial condition, results of operations and prospects. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Operational Dependence

Other companies may operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on our financial and operational results. See "*Industry Conditions – Liability Management Rating Programs*" and "*Third Party Credit Risk and Delay in Cash Receipts*" in these Risk Factors.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which we have assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business, as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Reservoir Pressure Maintenance

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

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase our costs of compliance.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. See "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs 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 generally required. Changes to the required ratio of our deemed assets to deemed liabilities, or other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. In addition, the liability management regime may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

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 and the Government of Alberta began revising Alberta's current liability framework with the introduction of the LMF in July 2020, which remains ongoing. ROK cannot predict how the Government of Alberta or the AER will seek to implement the LMF over the year, the LMF framework will have an impact on crude oil and natural gas production in Alberta, including ROK's business.

The AER's new LMF may impact the Corporation's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs, disclosure of information, increased scrutiny of the financial capabilities of both the transferee and the transferor 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 Corporation. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Corporation, and the associated abandonment, reclamation and remediation ("**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.

While the impact on the Corporation 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 Corporation and materially and adversely affect, among other things, the Corporation'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 jointly with the federal government, as the new LMF is implemented in the Province of Alberta. See "*Industry Conditions – Environmental Regulation*" and "*Industry Conditions – Liability Management Rating Programs*".

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole, or in part, with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable. Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. The Corporation has recently completed acquisitions and may complete future acquisitions and dispositions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of recent and any future acquisitions the Corporation may complete will depend in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of recent and any future acquisitions. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of ROK's non-core assets may realize less on disposition than their carrying value on the consolidated financial statements of the Corporation.

Competition

The petroleum industry is competitive in all of its phases. For example, competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. Because of their geographic diversity, larger and more complex assets, integrated operations and greater resources, some of these competitors may be better able to compete on the basis of price and to bear the economic risks inherent in all phases of the oil and natural gas industry. Further, the Corporation's ability to implement its business strategy will be dependent upon, not only our ability to explore and develop our present properties, but also our ability to evaluate and acquire other suitable producing properties or prospects for exploratory drilling and consummate transactions in a highly competitive environment.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of ROK. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing, transportation and royalty rates) are subject to extensive controls and regulations imposed by various levels of government, including those described above under the heading "*Industry Conditions*", which may be amended from time to time. ROK's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Changes to the regulation of the oil and gas industry in jurisdictions in which ROK operates may adversely impact ROK's ability to economically develop existing reserves and add new reserves.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

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

An increase in interest rates could result in a significant increase in the amount we pay to service any debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Corporation's securities.

Litigation

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

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Additionally, the Corporation may be subject to certain events beyond its control including, but not limited to, labour unrest, civil disorder, war, acts of terrorism, subversive activities or sabotage, fires, floods, explosions or other catastrophes, epidemics or quarantine restrictions. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Breach of Confidentiality

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

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Adverse weather conditions may adversely impact the timing and costs of the Corporation's plans.

Third Party Credit Risk and Delay in Cash Receipts

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of any potential joint venture partners may affect a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in us being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of ROK's properties, and by the operator to ROK, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of ROK's properties or the establishment by the operator of reserves for such expenses. In addition, the insolvency or financial impairment of any counterparty owing money to ROK, including industry partners and marketing agents, could prevent the Corporation from collecting such debts.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the CBCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the CBCA. See "*Directors and Officers – Conflicts of Interest*".

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities, which may be dilutive to shareholders.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Certain countries have imposed strict financial and trade sanctions against Russia, including with respect to oil and gas exports from Russia. These and any additional sanctions applied as the conflict continues may have a significant impact on worldwide prices of oil and natural gas and the world economy. The outcome and impact of the conflict and any sanctions imposed on Russia as a result remain uncertain.

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

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation.

See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Indigenous Claims

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

Information Technology Systems and Cyber-Security

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber-phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

Despite any efforts that we may make to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition, results of operations and the market value of the Corporation's securities.

Public Market Risk

There can be no assurance that an active trading market in the Corporation's securities will be sustained. The market price for the Corporation's securities could be subject to wide fluctuations. Factors such as commodity prices, government regulation, interest rates, share price movements of the Corporation's peer companies and competitors, as well as overall market movements, may have a significant impact on the market price of the securities of the Corporation. The stock market has from time to time experienced extreme price and volume fluctuations, particularly in the oil and gas sector, which have often been unrelated to the operating performance of particular companies.

Failure to Maintain Listing of the Class B Shares

The Class B Shares are currently listed for trading on the facilities of the TSXV. The failure of the Corporation to meet the applicable listing or other requirements of the TSXV in the future may result in the Class B Shares ceasing to be listed for trading on the TSXV, which would have a material adverse effect on the value of the Class B Shares. There can be no assurance that the Class B Shares will continue to be listed for trading on the TSXV.

Structure of the Corporation

From time to time, the Corporation may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of the Corporation and its subsidiaries. If the manner in which the Corporation structures its affairs is successfully challenged by a taxation or other authority, the Corporation and its prospects may be adversely affected.

Expansion into New Activities

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

Social Media

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. We monitor the social media activity of our employees on company-shared platforms and websites and designate certain individuals to carry out the release of information. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that we may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

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 ROK, its shareholders and the market value of ROK securities.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. ROK cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on its business, financial condition, results of operations and cash flows by decreasing profitability, increasing costs, limiting access to capital and decreasing the value of ROK's assets.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

Regulatory Actions

During the year ended December 31, 2021, there were (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely to be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as may be disclosed elsewhere in this AIF, none of the directors, executive officers, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 percent of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction or proposed transaction during the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Class B Shares is Odyssey Trust Company at its office located in Calgary, Alberta.

MATERIAL CONTRACTS

The Corporation has not entered into any contracts or agreements during the most recently completed financial year which remain in effect and which would be considered to be material to the Corporation.

Material Contracts entered into subsequent to the year ended December 31, 2021

1. Acquisition Agreement;

2. Underwriting Agreement; and

3. Senior Loan Facility.

For a description of the particulars of the contracts listed above, please see "*DEVELOPMENT OF THE BUSINESS – Relevant Three Year History*" in this AIF.

INTERESTS OF EXPERTS

KPMG LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, are contained in the Corporation's most recent information circular dated November 14, 2022 and available on SEDAR. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2021.