# ROK RESOURCES INC.

## ANNUAL INFORMATION FORM

for the year ended December 31, 2022

**June 27, 2023**

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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 2800, 500 4$^{th}$ Avenue SW, Calgary, Alberta, T2P 2V6.

## 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, 2022, 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, 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.

*Year ended December 31, 2022*

**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 $71.7 million ("**Transaction Value**" or "**TV**"), prior to realizing a downward purchase price adjustment of approximately $13.8 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 "**ACES Senior Loan Facility**"). The ACES Senior Loan Facility bore interest at a rate of US prime + 8.00% and was amortized over a four (4) year period (the "**Term**"). Under the terms of the ACES 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 was 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 ACES 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 ACES Senior Loan Facility is available on the Corporation's SEDAR profile at www.sedar.com.

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.

On December 19, 2022, the Company announced that it had entered into an Asset Exchange Agreement (the "**SE Sask Acquisition**") to acquire certain oil and gas assets (the "**SE Sask Assets**"), with associated production of approximately 1,500 boe/d (69% Liquids), in Southeast Saskatchewan from an Intermediate Energy Producer (the "**Vendor**") in exchange for total consideration of: (i) $26.5 million CAD in cash, before adjustments (the "**Cash Consideration**"), and (ii) an asset divestiture to the Vendor of certain of the Corporation's non-core assets, with associated production of approximately 475 boe/d (100% Liquids), in Southwest Saskatchewan (the "**Non-Core Assets**").

The Non-Core Assets sold to the Vendor included approximately 475 bbls/d (100% liquids) of production in the Butte area of Southwest Saskatchewan, including non-operated interests in the Butte Voluntary Unit, Bone Creek Unit and Eagle Lake Unit. The Corporation's average working interest in the Non-Core Assets was 15%, with the balance primarily owned and operated by the Vendor.

In connection with the SE Sask Acquisition, the Corporation entered into a commitment letter (the "**Commitment Letter**") with respect to a senior secured loan facility with a Canadian Chartered Bank for an aggregate principal amount of $75 million (the "**Senior Loan Facility**"). The Senior Loan Facility was to be comprised of: (i) a revolving credit facility in the amount of $22.5 million (the "**Credit Facility**"), and (ii) a 2-year term loan in the amount of $52.5 million (the "**Term Loan**"). The Senior Loan Facility would be used to fund the SE Sask Acquisition and completely payout the Corporation's existing higher cost debt facility, held by ACES, which was estimated to be $42 million at Closing and carried no pre-payment penalties. On December 23, 2022, the Corporation confirmed that the Senior Loan Facility was to be comprised of: (i) revolving credit facility in the amount of $22.5 million which the interest rate thereof is calculated on a sliding scale based on a debt-to-cash flow ratio and is expected to have an initial interest rate of approximately 8.15% at closing; and (ii) a non-revolving term loan in the amount of $52.5 million, amortized over no less than a two (2) year period, with an interest rate of Canadian Bankers' Acceptance rate plus 6.25%.

*Events subsequent to December 31, 2022*

On January 24, 2023, the Corporation announced that it had successfully closed the SE Sask Acquisition of the SE Sask Assets, in exchange for total consideration of approximately $23 million CAD in cash consideration after closing adjustments and the $2.5 million deposit paid in December 2022, and divestiture of the Non-Core Assets to the Vendor. The SE Sask Acquisition was funded through the previously announced Senior Loan Facility, which is comprised of the Term Loan and the Credit Facility. The Term Loan carries a monthly principal payment requirement of $2 million and has no prepayment penalty. The ACES Senior Loan Facility was repaid in full and replaced with the Senior Loan Facility, resulting in an interest cost reduction in excess of 30%.

On January 26, 2023, the Corporation announced the successful completion of a multi-layer perforation and swab test of a wellbore strategically located on one of Hub City Lithium Corp. ("**Hub City Lithium**") Subsurface Crown Mineral Dispositions located in the Mansur Area of Saskatchewan. Third-party laboratory testing returned lithium concentrations in the Duperow formation of up to 148 mg/l.

On February 16, 2023, the Corporation announced the results of its December 31, 2022, independent reserves evaluation. The evaluation for the Corporation as at December 31, 2022 was conducted by McDaniel & Associates ("**McDaniel**") of Calgary and was conducted in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluators Handbook ("**COGEH**") and National Instrument 51-101 - *Standards for Disclosure of Oil and Gas Activities* ("**NI 51-101**"). The reserve volumes do not include the SE Sask Acquisition.

On February 21, 2023, the Corporation announced the successful drilling and multi-layer perforation and flow test of a wellbore strategically located on one of Hub City Lithium Subsurface Crown Mineral Dispositions located in the Viewfield Area of Saskatchewan. Third-party laboratory testing returned lithium concentrations in the Duperow formation of up to 259 mg/l (the "**Test Results**"). According to public records, these Test Results are the highest lithium concentrations ever recorded in a brine in Canada.

On March 23, 2023, the Corporation announced it entered into separate Asset Purchase and Sale Agreements (the "**Dispositions**") to divest of certain non-core assets in Saskatchewan for total combined proceeds of approximately $47.25 million, which included the sale of the Corporation's non-operated 2.11685% interest in the Weyburn Unit (the "**Weyburn Unit**") to Rife Resources Ltd. ("**Rife Resources**") for total proceeds of approximately $44.5 million, before normal closing adjustments (the "**Rife Transaction**"). Two smaller dispositions (the "**Other Assets**") make up the balance of the Dispositions for total proceeds of $2.75 million, before normal closing adjustments. The Other Assets include: (i) approximately 5,000 net acres of fee title land in Southwest Saskatchewan, and (ii) approximately 40 boe/d of non-core production, for total proceeds of $2.75 million. The proceeds will be as allocated to working capital for the Corporation's upcoming 2023 drilling program. These transactions subsequently closed on April 3, 2023.

On April 20, 2023, the Corporation announced the results of its April 1, 2023, independent reserves evaluation (the "**Evaluation**"), which was conducted by McDaniel and was conducted in accordance with the definitions, standards and procedures contained in COGEH and NI 51-101. The reserve volumes are inclusive of the Corporation's recent divestitures and acquisitions and represent corporate reserve volumes as of April 1, 2023. The Evaluation is highlighted by the addition of 3.2 million Boe of proved oil and gas reserves ("**1P**"), to a total of 13 million Boe, a 34% increase when compared to December 31, 2022. The Corporation also added 5.4 million Boe of proved plus probable oil and gas reserves ("**2P**"), to a total of 21.5 million Boe, a 35% increase compared to December 31, 2022. Other highlights includes 1P oil and gas reserves of 13,016 MBoe and Net Present Value of 1P reserves discounted at 10% of $135.2 million; 2P oil and gas reserves of 21,552 MBoe and Net Present Value of 2P reserves discounted at 10% of $257.8 million; Total 1P NAV of $0.59/basic share and 2P NAV of $1.17/basic share, up 25% and 35% respectively from year-end 2022; 1P reserve life index ("**RLI**") of 9 years and 2P RLI of 15 years, representing a 16% increase to both 1P & 2P RLI; an increase in booked locations from 58 gross to 124 gross, up 114% from year-end 2022; and estimated future undiscounted development costs of $142 million (1P) and $194 million (2P), or $10.91 per 1P Boe and $9.00 per 2P Boe.

On May 2, 2023, the Corporation announced the full repayment of the Term Loan, 20 months prior to expiry. The Term Loan was obtained in January 2023 and was fully repaid, without pre-payment penalties, through a combination of monthly operating cash flow and strategic non-operated asset dispositions. The Corporation has retained a $22.5 million revolving credit facility, with current net debt estimated at $10 million.

The Corporation also announced, as a twenty-five percent (25%) shareholder and manager of operations of Hub City Lithium, the results of Hub City Lithium's National Instrument 43-101 technical report on the lithium brine potential and preliminary resource assessment ("**Preliminary Assessment**"). The Preliminary Assessment confirms an inferred lithium resource of 1.15 million tonnes of lithium carbonate equivalent ("**LCE**") at an average grade of 143 mg/l. The Preliminary Assessment evaluated more than 300 wells within the region and evaluated eight (8) stacked zones of high lithium concentrations. The full resource report was filed on SEDAR on May 8, 2023, and is available under the Corporation's SEDAR profile at www.sedar.com.

**Significant Acquisitions**

The Corporation did complete a significant acquisition, being the Acquisition, during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. The business acquisition report with respect to same is 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 13, 2023 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, 2022, the Corporation has recorded an uninflated and undiscounted decommissioning obligation of $52.4 million. 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, 2022, ROK had 20 employees. As at the date hereof, ROK has 27 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.

### 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, 2022, ROK had total revenue from its properties of approximately $87.3 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 June 27, 2023:

| Name and Municipality of Residence | Office[4] | Principal Occupation | Director Since[5] and Shares currently held, directly or indirectly |
|---|---|---|---|
| Cameron Taylor[1][2]<br>Wolseley, SK<br>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<br><br>10,459,410 |
| Lynn Chapman<br>Calgary, Alberta<br>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<br><br>270,000 |
| Kent McDougall[1][3]<br>Calgary, Alberta<br>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<br><br>3,184,000 |
| Jeff Chisholm[2]<br>Bangkok, Thailand | Director | Mr. Chisholm is a geoscientist with 35 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 was President, CEO and Director of Pan Orient Energy Corp., an oil and natural gas company from July 2005 to August 2022 where he managed a debt free balance sheet and returned significant capital to Pan Orient shareholders. Mr. Chisholm is currently the President, CEO and Director of Canasia Energy Corp.. | August 13, 2020<br><br>3,776,922 |
| Jared Lukomski<br>Regina, Saskatchewan<br>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<br><br>7,455,601 |

| Name and Municipality of Residence | Office[4] | Principal Occupation | Director Since[5] and Shares currently held, directly or indirectly |
|---|---|---|---|
| Bryden Wright<br>Regina, Saskatchewan<br>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<br><br>5,706,292 |
| David Hergenhein[(1)(2)(3)]<br>Calgary, Alberta<br>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<br><br>735,600 |
| Peter Yates[(2)(3)]<br>Calgary, Alberta<br>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<br><br>504,999 |
| Thomas MacInnis<br>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<br><br>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 35,791,324 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, 2022 | KPMG | $251,250 | $82,925 | $15,349 | $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 214,873,217 Class B Shares were issued and outstanding as at June 27, 2023. 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 year ended December 31, 2022 filed by the Corporation on April 13, 2023 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** |
| **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 | 0.49 | 0.41 | 5,503,000 |
| **2023** | | | |
| January | 0.48 | 0.42 | 6,163,100 |
| February | 0.43 | 0.39 | 6,726,400 |
| March | 0.42 | 0.33 | 8,804,500 |
| April | 0.43 | 0.36 | 3,948,900 |
| May | 0.38 | 0.32 | 3,005,800 |
| June 1-27 | 0.36 | 0.29 | 2,282,215 |

*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 | 0.27 | 0.21 | 1,415,448 |
| **2023** | | | |
| January | 0.26 | 0.21 | 3,418,777 |
| February | 0.22 | 0.18 | 3,381,777 |
| March | 0.22 | 0.13 | 3,105,981 |
| April | 0.22 | 0.16 | 2,626,226 |
| May | 0.17 | 0.14 | 949,441 |
| June 1-27 | 0.15 | 0.10 | 887,500 |

## STOCK OPTION GRANTS

As of December 31, 2022, the Corporation granted, under the Corporation's stock option plan (the "**Option Plan**"), options ("**Options**") to acquire an aggregate of 19,283,333 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 |
| March 25, 2022 | 10,343,333 | $0.25 | March 25, 2027 |
| August 31, 2022 | 1,550,000 | $0.30 | August 31, 2027 |
| October 31, 2022 | 800,000 | $0.35 | October 31, 2027 |

**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 1,450,000 Options in March 2023 to certain employees of the Corporation.

## 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.

In 2020, worldwide oversupply of crude oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a continuing significant impact on the pricing of crude oil. In an effort to stabilize global oil markets, OPEC and a number of other oil producing countries announced an agreement to cut crude oil production by approximately 10 million bbl/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. The oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022 primarily in response to the to the impact of the Russian invasion of Ukraine and the Organization of the Petroleum Countries Plus ("**OPEC+**") decision to adhere to previously agreed upon production cuts, together with the improvement of global economic conditions and outlook due to reduced and eased COVID-19 restrictions. However, prices began to drop in the latter half of 2022. Amid fear of a global recession, increasing interest rates and continuing COVID-19 restrictions in China, lower demand and continuing sanctions and price caps placed on Russian oil, oil prices began to drop in the summer of 2022, with Saudi Arabia capping production and the Group of Seven nations agreeing to put a price cap on Russian oil. At a meeting in early December 2022, OPEC+ decided to maintain its oil output targets following its decision in October 2022 to cut output by 2 million barrels per day. In December 2022, the Group of Seven Nations and the European Union agreed on a ban on seaborne exports of Russian-origin crude oil, placing a price cap at US$60 per barrel, effective December 5, 2022. The European Union also announced a price cap which can be triggered starting February 15, 2023 if prices for natural gas exceed 180 euros per megawatt hour for three days on the Dutch Title Transfer Facility gas hub's front-month contract. On February 4, 2023, the European Union introduced a price cap on certain Russian petroleum products, effective February 5, 2023, covering certain petroleum products that are traded at a discount or at a premium to crude oil.

With a continuing shift to alternative energy sources, there has been a decline in oil demand growth, which is expected to continue into 2023. While the trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as the continued COVID-19 restrictions in China and conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – COVID-19 Pandemic and Associated Risks*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

**Natural Gas**

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

**Natural Gas Liquids**

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

**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.

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.

**Transportation Constraints and Market Access**

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

**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. In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns like greenhouse gas ("**GHG**") emissions from the ultimate burning of the crude oil carried in the pipeline.

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 proceeded 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. On March 10, 2023 Trans Mountain Corporation announced that construction of the Trans Mountain Pipeline expansion is close to 80% complete, with mechanical completion expected to occur at the end of 2023 and the pipeline in service in the first quarter of 2024, and that once the pipeline system is complete that it is anticipated to have a capacity of 890,000 barrels per day.

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 the date of this AIF, no permanent rules have been approved.

Following midterm elections in the fall of 2022, the Republicans have regained control of the House of Representatives. While the Republican's political agenda is expected to include acts regarding American energy independence, it is uncertain what this will mean for the advancement of pipeline projects between Canada and the United States.

**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 and NGL**

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 Protocol, which was opposed by NOVA Gas Transmission Ltd. and ultimately denied by the CER in February 2021. In January 2022, the CER issued its decision denying NOVA Gas Transmission Ltd.'s application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

Additionally, while a number of NGL export plants have been proposed in Canada, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the NGL Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow NGL Canada to transport natural gas from northeastern British Columbia to the NGL 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**"). The CGL Pipeline is being built by TC Energy. Pre-construction activities began in November 2018, with a completion target of 2025. In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline. According to an announcement from TC Energy dated April 28, 2023, the CGL Pipeline is approximately 87% complete and is slated to have a mechanical in-service date by the end of 2023.

In December 2019, the CER approved a 40-year export licence for the Kitimat NGL project (the "**Woodfibre NGL Project**"), a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. However, both partners are looking to sell some or all of their interest in the project. Both parties elected to cease funding further feasibility work for the proposed Woodfibre NGL Project with both parties exiting the project. The Woodfibre NGL Project is a small-scale NGL processing and export facility near Squamish, British Columbia. As of July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement, pursuant to which they have agreed to jointly invest in the construction and operation of the Woodfibre NGL Project. The BC Oil and Gas Commission ("**BC Commission**") approved a project permit for the Woodfibre NGL Project in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin the work required to move the project toward major construction commencement in 2023. The Woodfibre NGL Project is expected to be substantially completed in Q3 2027. In November 2022, certain amendments to the conditions listed in the Impact Assessment Agency of Canada's decision statement for the project were proposed, which were made available for public comment until December 2022.

GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an NGL facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026. Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro NGL project, located in Nova Scotia, would see NGL exported from Canada to European markets. Pieridae has a downstream agreement with Uniper, a German utility, for all of the NGL produced at Goldboro's liquefaction facilities. The federal government has issued Goldboro NGL a 20-year export licence, but Pieridae decided in July 2021 not to proceed with the project.

Cedar NGL Export Development Ltd.'s Cedar NGL Project near Kitimat, British Columbia ("**Cedar NGL**"), is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**"). On June 8, 2021 the Haisla First Nation and Pembina Pipeline Corporation announced a partnership agreement whereby Pembina Pipeline Corporation will become the Haisla Nation's partner in the development of the Cedar NGL Project. Cedar NGL received its Environmental Assessment Certificate from the B.C. Environmental Assessment Office on March 14, 2023 and on March 15, 2023, received a positive Decision Statement from the federal Minister of Environment and Climate Change.

Ksi Lisims NGL project, owned by Nisga's Lisims Government, Rockies NGL Partners and Western NGL is currently in the environmental assessment stage, with the BC EAO conducting the environmental assessment on behalf of the IA Agency. Construction is anticipated to begin in 2024 with the site operational in late 2027 or 2028.

**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 United States Mexico Canada 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**". The USMCA came into force on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Corporation's business.

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

**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 has not received full ratification by 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 ("**Brexit**") on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, *an Act to Implement the Trade Continuity Agreement*. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and 10 other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, and Peru. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

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

## 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.

**Regulatory Authorities and 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. Further, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents ("**CO2e**")), may impose further requirements on operators and other companies in the petroleum and natural gas industry.

**Federal**

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

On August 28, 2019, the IAA replaced the *Canadian Environmental Assessment Act*, 2012 ("**CEAA 2012**") at the same time that the CERA replaced the NEB Act and the CER replaced the NEB. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency").**

The IAA is similar to the repealed CEAA 2012 in that it relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights and peoples. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal Government has appealed the Alberta Court of

Appeal's opinion to the SCC. The SCC heard the matter in late March 2023 and, as of the date of this AIF, a decision on the matter has not been delivered by the SCC.

On June 21, 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement *the United Nations Declaration of the Rights of Indigenous Peoples* as a framework for reconciliation in Canada

**Saskatchewan**

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. The *Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations*, 2012 (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "Registry **Regulations**"). The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex database.

The environmental scheme in Saskatchewan is governed by *The Environmental Management and Protection Act*, 2010 *and The Forest Resources Management Act*. In Saskatchewan, the ministry has adopted a results-based regulatory model which largely leaves the determination of how environmental protection is to be achieved with the respective proponent.

**Alberta**

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* (Alberta) and a number of related statutes including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act* and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands and protecting the environment. The AE''s responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas (previously known as the Ministry of Environment and Parks), the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy in Alberta 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 AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production.

In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in Subsurface Order Nos. 2, 6 and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions, and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

**Liability Management Rating Programs**

**Saskatchewan**

The Saskatchewan Ministry of Energy and Resources administers the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licencee'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 takes on the obligation of 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 for financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires all new licencees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licencees whose deemed liabilities exceed their deemed assets (*i.e.*, an LLR below 1.0) are required to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licencees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities and this data is publicly available. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to *Redwater Energy Corporation (Re), 2016 ABQB 278* ("**Redwater**"). Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

**Alberta**

The AER oversees liability management in the province. On July 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF**") for the oil and gas industry which is intended to replace the Alberta Liability Management Program (the "**AB LMR Program**"). The goal of the AB LMF is 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 AB LMF through legislative and AER directive amendments.

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the "**Redwater Decision**"). As a result of the Redwater Decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. 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 licencee'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.

Alberta's OGCA 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 Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former Licensee Liability Rating Program (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 $335 million. The Government 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 to 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. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater Decision, Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. It is the goal that the AB LMF will assist in addressing the OWA's inventory, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a 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 AB 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 AB LMF, the AB LLR Program and security deposit collection for licence transfer have been 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 AB LMF provides proactive support to distressed operators and requires 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 AB LMF each licencee is required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from $422 million to $700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

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% 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 of 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 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 five-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF and properly phase-out the AB LMR Program as the AB LMR Program is integrated in several directives and throughout governing legislation.

**Federal and Provincial Support for Liability Management**

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program, which is closed to new applicants. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: (i) the Dormant Sites Reclamation Program, which requires all work to be complete by December 31, 2022; (ii) the Orphan Sites Supplemental Reclamation Program; and (iii) the Legacy Sites Reclamation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to $100 million of an existing $235 million loan to the Orphan Fund. In Saskatchewan, $400 million in federal funding was used for the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP made $100 million available to eligible service companies to conduct abandonment and reclamation work. The ASCP is in the final year of operation, with the program ending in the spring of 2023. In July 2022, the ASCP opened application processes to release all remaining ASCP funding to eligible licensees.

**Climate Change Regulation**

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the petroleum and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

**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.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the "**2030 Reduction Plan**"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**") which builds on the Pan-Canadian 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, in June 2022, the federal government introduced the *Single-use Plastics Prohibitions Regulations* ("SUPPR"). The SUPPR prohibits, subject to certain exemptions, the manufacture, import and sale of single-use plastic checkout bags, cutlery, foodservice ware made from or containing problematic plastics, ring carriers, stir sticks and straws. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

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 greenhouse gas 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. The *Canadian Net-Zero Emissions Accountability Act* became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines 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 "**GGPPA**"), 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 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 federal standards. 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. In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO2e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards (the "**federal benchmark**") for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

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 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 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 of 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 national stringency standards or federal benchmarks. Currently the Fuel Charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the OBPS applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. The provincial plans for each of Nova Scotia, Prince Edward Island

and Newfoundland and Labrador were deemed by the federal government to have fallen short of the federal benchmark, making the federal OBPS applicable in each of those provinces as of July 1, 2023. For so long as the provincial systems in 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 petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane, as well as ensuring that crude oil and natural gas operations use lower emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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 October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

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

The federal government has also announced that it will proceed with the development and implementation of a Clean Fuel Standard ("**CFS**") that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, with the *Clean Fuel Regulations* ("**CFS Regulations**") coming into force on June 21, 2022. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5 g CO2e/MJ, increasing by 1.5 gCO2e/MJ each year and reaching 14 gC02e/MJ in 2030. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits, tracked via the Credit and Tracking System, and created a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

**Saskatchewan**

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. The Government of Saskatchewan subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* (the "**Saskatchewan Strategy**") outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system and was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the province of Saskatchewan received confirmation that a provincial plan has been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS meets the federal stringency requirements and regulated emitters will receive credit for every tonne of CO2e under their permitted amount.

The OBPS program in Saskatchewan will also include credits for CCUS. The OBPS program in Saskatchewan is implemented under the Saskatchewan Strategy. As noted above, the federal fuel charge applies in Saskatchewan.

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 CO2e 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% to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

On April 10, 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

In October 2019, *The Oil and Gas Conservation Amendment Act* was proclaimed into force. This Act, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

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. 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.

**Alberta**

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (Alberta) (the "**CLA**") came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the Government of Alberta repealed the CLA and the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $50/tonne of CO2e and will increase to $65/tonne on April 1, 2023. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted in. The TIER regulation came into effect on January 1, 2020 and replaced the previous *Carbon Competitiveness Incentives Regulation*.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the *Technology Innovation and Emissions Amendment Regulation* was adopted with certain amendments to the TIER Regulation which came into effect January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for carbon capture, utilization and storage ("**CCUS**") projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies 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% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high-performance benchmarks. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO2e to 2,000 tonnes of CO2e per year. 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.

As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta aims to lower annual methane emissions by 45% 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*. 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 CCUS technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale CCUS projects. Both projects will help reduce the $CO_2$ emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 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. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

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. The Alberta Utilities Commission also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

**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.

**Indigenous Rights**

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

On November 28, 2019, the *Declaration on the Rights of Indigenous Peoples Act* (the "**DRIPA**") became law in British Columbia. The Government of British Columbia recently released its interim approach in furtherance of its implementation of DRIPA which outlines a process for how new policy and legislation in the province are to be aligned with the UNDRIP. The action plan is the first of its kind to be enacted by any province and it is uncertain as to what potential consequences the implementation of the plan and its effects on future legislative drafting.

Similar to British Columbia's DRIPA, the *United Nations Declaration of the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and natural gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The federal government has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that, subject to the forthcoming opinion from the SCC, the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in Northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in Northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nation Implementation Agreement ("**Implementation Agreement**"). On January 20, 2023, the Government of British Columbia also finalized a co-developed set of initiatives ("**Consensus Document**") with four other Treaty 8 First Nations, including the Fort Nelson, Saulteau, Halfway River and Doig River First Nations ("**Treaty 8 Nations**"). Both the Implementation Agreement and the Consensus Document respond to the Blueberry Decision. The precedent established by the Implementation Agreement and the Consensus Document may extend beyond Treaty 8 territory and may have implications for resource development in Saskatchewan, Alberta and Canada at large.

The key elements of the Implementation Agreement are:

- *Wildlife Management*: The Government of British Columbia and BRFN are committing to bring together Indigenous knowledge and western science. Both parties will support a community stewardship, monitoring and guardian program. Further, important species will be closely monitored.

- *Land-Use Pla*ns: The Government of British Columbia and BRFN will engage in collaborative land use planning, to determine whether certain activities can occur in Treaty 8 territory.

Collaborative land-use planning includes a commitment to advance watershed-level land use plans within the next three years ("**Watershed Management Basin Plans**").

- *Petroleum and Natural Gas*: The Government of British Columbia and BRFN will use a more collaborative approach to oil and natural gas development planning and projects. The Government of British Columbia, various companies and other First Nations will sit together and address: the establishment of areas for permanent protection; minimizing disturbance from petroleum and natural gas development; reducing new disturbance from petroleum and natural gas by approximately 50 percent from pre-Blueberry Decision years; introducing operational and strategic planning expectations for the sector; and limiting overall new disturbances from petroleum and natural gas activities in BRFN's claim area.

- *Forestry*: The Government of British Columbia and BRFN will protect old growth forest and reduce timber harvesting in defined high value areas. Key elements of the Implementation Agreement applicable to forestry include: a cessation to aerial herbicide use; a commitment to implementing ecosystem-based management, through Watershed Management Basin Plans; and two-year harvest schedule outside the BRFN's important forestry areas.

- *Honoring Treaty 8*: The Government of British Columbia and BRFN have agreed to work together on measures to honor Treaty 8, including improving awareness and education on Treaty 8. The Government of British Columbia and BRFN will honor Treaty 8 by sustaining communications, sharing training and awareness building, and providing support for communications with other Treaty 8 First Nations and local elected elders.

The Implementation Agreement also includes a $200 million restoration fund, which is meant to restore the land from industrial disturbance by June 2025. Further, BRFN will receive $87.5 million as a financial package, with an opportunity for increased benefits based on petroleum and natural gas revenue-sharing and provincial royalty revenues in the next two years. According to the Government of British Columbia, the Consensus Document will address the cumulative impacts of industrial development on the meaningful exercise of Treaty 8 rights in the territory, restore land and produce stability and predictability for industry in the region and to promote responsible resource development and sustainable economic growth in Treaty 8 territory. Further, it aims to manage the impacts of industrial development through ecosystem-based stewardship and governance. The Consensus Document sets out various initiatives to outline how the Government of British Columbia and Treaty 8 Nations manage the land to achieve sustainability for future generations, meet the Crown's obligations to uphold constitutionally protected rights and support responsible resource development and economic activity in northeastern British Columbia. Specifically, the initiatives outlined in the Consensus Document include: (i) a new approach to wildlife co-management; (ii) new land-use plans and protection measures; (iii) a "cumulative effects" management system; (iv) pilot projects to advance shared decision-making for environmental planning and stewardship; (v) a multi-year, shared restoration fund; (vi) a new revenue sharing approach to support the priorities of Treaty 8 First Nation communities; and (vii) actions to promote education about Treaty 8 through collaborative promotion, anti-racism training and awareness building.

The Government of British Columbia is still in ongoing discussions with other Treaty 8 First Nations, including McLeod Lake Indian Band, Prophet River First Nation and West Moberly First Nations.

The Implementation Agreement and Consensus Document remain confidential at the date of this AIF. Although the details have not been released, it is highly likely those documents will create additional consultation and regulatory obligations for operators seeking to develop natural resources in the affected region.

In July 2022, the Duncan's First Nation in Northern Alberta filed a lawsuit claiming cumulative effects from industry, agriculture and settlement which violate their treaty rights. The claim advances many of the same grounds as those that were the subject of the Blueberry Decision.

The long-term impacts and risks of the Blueberry Decision, and any subsequent decisions, on the Canadian oil and natural gas industry remain uncertain.

## 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 Pandemic and Associated Risks

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on our 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 continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. At the onset of the COVID-19 pandemic in March 2020, governments and regulatory bodies in affected areas imposed a number of measures designed to contain the COVID-19 pandemic, including widespread business closures, social distancing protocols, travel restrictions, quarantines, curfews and restrictions on gatherings and events. While substantially all containment measures in Canada have been lifted, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 may be instituted in line with guidance of public health authorities. Additional waves of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains may lead to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures have the potential to impact global economic activity and such measures may also contribute to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. The prolonged effects of any disruption may have adverse impacts on our business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks. Low prices for crude oil, NGL and natural gas would reduce the Corporation's cash flow from operating activities and impact the Corporation's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, the effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness and temporary closures of the Corporation's facilities. Uncertainty remains as to the full impacts of the COVID-19 pandemic on the global economy, commodity and financial markets, crude oil and natural gas capital investment levels and the energy business more broadly. The ultimate impacts will depend on future developments that are highly uncertain and cannot be predicted, including the scope, severity, duration and additional subsequent waves of the COVID-19 pandemic, including the introduction of new variants, as well as the effectiveness of actions and measures taken by the various levels of government. If the COVID-19 pandemic is further prolonged, including the possibility of additional subsequent waves, and introduction of new variants, or further diseases emerge 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*”.

**Commodity Prices, Markets and Marketing**

The Corporation's revenue, operating results and financial condition depend substantially on the prevailing prices for crude oil and natural gas and the Corporation's ability to successfully market its oil and natural gas production from its properties. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced or discovered by the Corporation.

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 (see "*Industry Conditions - Pricing and Marketing in Canada*" and "*Risk Factors - Weakness and Volatility in the Oil and Gas Industry*"). 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.

Crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to 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, the war in Ukraine, concerns regarding COVID-19 and its impact on the supply of, and demand for, crude oil, NGL and natural gas, global crude oil, NGL and natural gas inventory levels, weather conditions affecting supply and demand, overall domestic and global economic conditions, currency fluctuations, social attitudes or policies affecting energy consumption and energy supply, domestic and foreign governmental regulations, including environmental regulations, climate change regulations and taxation, the effects of energy conservatism efforts and GHG reduction measures, the price, availability and acceptance of alternative energies, including renewable energy, and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. A material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of the Corporation's anticipated production revenue.

The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of 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 and Volatility in the Oil and Gas Industry*" in these Risk Factors.

Volatile crude 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 crude oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic for development. The Corporation's reserves at December 31, 2022 are estimated using forecast prices and costs. If crude oil and natural gas prices decrease, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices may restrict the Corporation's cash flow resulting in less funds being available to fund the Corporation's capital expenditure programs. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over-year basis.

Additionally, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write-down of the carrying value of its crude oil and natural gas assets on its balance sheet and the recognition of an impairment charge on its income statement.

**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. The lack of available capacity in any of the gathering and processing facilities, pipeline systems and railway lines could negatively affect ROK's business, financial condition, results of operations and prospects.

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.

**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 American 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 was unprecedented in the United States, and the short and long-term impacts on business and capital markets are unknown. Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. It is unclear what the impact of the new executive order will be and how it may impact the USMCA and the Canada-U.S. supply chain. Further, 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 petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian crude oil and natural gas companies, which could also negatively impact the Corporation, which negative impact could prove to be material over time.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined, especially in a post-pandemic era. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Corporation's business could increase and access to skilled labour could decrease, negatively impacting the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and impact demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

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 petroleum and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the SCC unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain between provincial and federal governments. Continued uncertainty and delays, including a temporary shutdown due to flooding in British Columbia have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Corporation's operations are located.

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced Bill 1: The Alberta Sovereignty Within a United Canada Act (the "**Sovereignty Act**"). The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA and the IAA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act's constitutionality will be challenged.

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*".

**Inflation and Cost Management**

The Corporation's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Corporation's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Corporation's financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects.

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

**Weakness and Volatility 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. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022 and are expected to continue throughout the first half of 2023. It is anticipated that the petroleum and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum and natural gas industry. Such 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*" and "*Political Uncertainty*" 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.

**Changing Investor Sentiment**

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of crude 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 petroleum 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 crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices, including the use of environmental metrics in executive compensation. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the petroleum and natural gas industry, and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's assets which may result in an impairment charge.

**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. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce crude oil and natural gas reserves, as well as to acquire additional crude oil and natural gas assets to contribute to additional crude oil, natural gas and NGL reserves.

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.

**Capital and Additional Funding Requirements**

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. Future capital and other expenditures will be financed out of cash generated from operations, borrowings and possible future equity issuances and the Corporation's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; the Corporation's credit rating (if applicable); commodity prices; interest rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and the Corporation's securities in particular. Due to the conditions in the petroleum and natural gas industry and/or global economic and political conditions and the domestic lending landscape, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the petroleum and natural gas industry have negatively impacted the cost and/or ability of crude oil and natural gas companies to access additional financing.

There can be no assurance that debt or equity financing, or cash flow generated by operations, will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Alternatively, any available financing may be highly dilutive to existing shareholders. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected. The inability of the Corporation to access sufficient capital for its operations could cause the Corporation to, amongst other things, miss certain acquisition opportunities and may materially adversely affect the Corporation's business and financial condition.

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, miss certain acquisition opportunities and reduce or terminate our operations, 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 may 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 of Securities**

The trading price of the securities of crude 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 the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities. Similarly, the market price of the Corporation's securities could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Corporation's securities will trade cannot be accurately predicted.

**Climate Change**

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact.

*Transition Risks*

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented.

However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets. See "*Risk Factors – Non-Governmental Organizations*" and "*Risk Factors – Reputational Risk*". Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Corporation, impact its operations and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts require the Corporation's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets, which negative impact could prove to be material over time. Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51- 107 – Disclosure of Climate-related Matters, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

*Physical Risks*

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts.

Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the ability of the Corporation to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions for the Corporation, its employees and contractors.

*Chronic Physical Climate Change Risks*

The Corporation's operations and activities associated with the Corporation's projects and assets emit GHGs which may require the Corporation to comply with federal and/or provincial GHG emissions legislation. 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 to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effects could prove material over time. There is no guarantee the current provincial regimes in place will continue to meet federal stringency requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Corporation to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety, which may in turn have a negative effect on the Corporation's production which negative effect could prove material over time. Specifically, in the event of water shortages or sourcing issues, the Corporation may not be able to, or will incur greater costs to, carry out hydraulic fracturing.

Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to reduced demand for the crude oil, natural gas and NGLs, which would have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Risk Factors – Alternatives to and Changing Demand for Petroleum Products*".

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

*Acute Physical Climate Change Risks*

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with the Corporation’s operations, increasing costs and negatively impacting the lessee or operator's production.

Certain of the Corporation’s operations are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting the Corporation’s operations.

**Environmental**

All phases of the crude oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with petroleum and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. See “*Industry Conditions – Exports from Canada*”, “*Industry Conditions – Regulatory Authorities and Environmental Regulation*” and “*Industry Conditions – Climate Change Regulation*”.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties on such lessees or operators, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge; however, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a negative effect on the Corporation's business and financial condition, which negative effect could prove material over time.

Stakeholders, the public and provincial and federal governments are becoming increasingly concerned about habitat and species protection, including degradation to biodiversity caused by economic activity. Accordingly, governments at various levels are increasing the rigour of existing acts and regulations and issuing changes aimed at improving environmental protection. The Corporation and its employees, consultants and operators may disturb the surrounding biodiversity of its properties with the requirement for earth moving and the footprint of crude oil and natural gas operations. This may result in impacts to flora and fauna, including species at risk. Operations on the Corporation’s properties may also be affected by conditions or restrictions on operations caused by wildlife habitat and migration patterns, endangered species or species at risk, and vegetation located on the Corporation’s properties. The Corporation may fail to achieve necessary permits or be subject to penalties or litigation if they cause habitat destruction or otherwise fail to mitigate impacts on biodiversity on the Corporation’s properties. There is no assurance that the Corporation will effectively limit habitat destruction or mitigate the impacts on biodiversity on its properties. If the Corporation fails to do so, there may be decreased activities on the Corporation’s properties, which could have an adverse effect on the Corporation’s business and financial condition.

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.

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. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*".

**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 – Regulatory Authorities and 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 – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Liability Management Rating Programs*".

**Energy Transition**

Globally, there is an increasing focus on transitioning to a low-carbon economy resulting in a number of policies and initiatives designed to shift resources and investment away from fossil fuels towards low carbon sources. This includes government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption. The Corporation is constantly evaluating its options with respect to increasing environmental efficiency through its operations. However, there can be no assurances that the Corporation will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Corporation's business and financial condition.

**Evolving Corporate Governance, Sustainability and Reporting Framework**

The Corporation's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Corporation's securities. The Corporation is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities administrators, the Toronto Stock Exchange and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Corporation's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

**Availability and Cost of Material and Equipment**

Crude 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 areas where such activities will be conducted. The availability of such material and equipment is limited. The oil and natural gas industry is cyclical in nature and is prone to shortages of supply of equipment and services, including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation’s operations and may delay such exploration, development and operating activities, which, in turn, could materially adversely affect the Corporation's business and financial condition.

**Reputational Risk**

The Corporation's business, financial condition, operations or prospects may be negatively impacted, which negative impact could prove to be material over time, as a result of any negative public opinion toward the Corporation or as a result of any negative sentiment toward or in respect of Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain crude oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation’s operations could damage the reputation of and, in turn, the Corporation, in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for the Corporation to operate its business. In addition, negative sentiment towards the Corporation could result in the residents of the areas where the Corporation is doing business opposing further operations in the area by the Corporation. The Corporation's reputation could be affected by actions and activities of other corporations operating in the petroleum and natural gas industry, over which the Corporation has no control. If the Corporation, either directly or indirectly develops a reputation of having an unsafe workplace it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to crude oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Corporation's reputation.

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

**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.

**Reserves 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 or required by applicable securities laws, has not been updated and therefore does not reflect changes in our reserves since that date.

**Dividends**

The amount of future cash dividends paid by the Corporation, if any, is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition of the Corporation; results of operations; capital expenditure requirements; working capital requirements; operating costs; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; the Corporation's risk management activities or programs; the Corporation's business plan, strategies and objectives; tax laws; foreign exchange rates; interest rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which are beyond the control of the Corporation, the Corporation's dividend policy and, as a result, future cash dividends, could be reduced or suspended entirely, from time to time. The Corporation’s credit facilities may prohibit the Corporation from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

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. Over time, the Corporation's capital and other cash needs may change significantly from its current needs, which could affect whether the Corporation pays dividends and the amount of dividends, if any, it may pay in the future. If the Corporation elects to pay a dividend, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. A decline in the market price, liquidity, or both, of the Corporation's securities could result if the Corporation reduces or eliminates the payment of dividends, which could result in losses to shareholders.

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.

**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, companies that may operate some of the assets in which the Corporation has an interest may be in or encounter 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 high pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of crude 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 the costs of compliance and doing business as well as delay the development of crude 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 crude oil and natural gas that is ultimately produced from the Corporation's reserves and, therefore, could materially adversely affect the Corporation's business, financial condition, results of operations and prospects.

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

Additionally, the Corporation must dispose of the fluids produced from crude oil, NGL and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. See "*Risk Factors – Disposal of Fluids Used in Operations*".

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

**Waterflood**

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 business, financial condition, results of operations and prospects.

**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 the costs of compliance the Corporation which may impact the economics of certain projects and in turn impact activity levels and new capital spending.

**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, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. See "*Industry Conditions – Regulatory Authorities and 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 licencee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continue to implement the AB LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase-out the AB LMR Program. The implementation of the AB LMF or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by the Corporation, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Corporation which could in turn materially adversely affect the Corporation's business and financial condition. The impact and consequences of the SCC's Redwater Decision on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMF may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude 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. . See "*Industry Conditions – Regulatory Authorities and 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**

The Corporation considers acquisitions and dispositions of assets in the ordinary course of business, and 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 acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. The Corporation may also enter into other industry-related activities or new geographical areas or acquire different energy-related assets that may result in unexpected or significantly increased risk to the Corporation, which could materially adversely affect the Corporation's business, financial condition, results of operations and prospects. Management continually assesses the value and contribution of the various properties and assets within its portfolio. In this regard, the Corporation may consider disposing of certain non-core assets in-order to focus its efforts and resources more efficiently. Depending on market conditions for such non-core assets, the Corporation may realize less on disposition of certain core assets than their carrying value on the financial statements of the Corporation.

**Industry 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.

**Management of Growth and Integration**

The Corporation may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. In particular, the Corporation is responsible for managing a substantial number of land and title documents and related accounting functions that require significant employee resources. The ability of the Corporation to manage future growth and integration of additional lands, leases and acquisitions effectively requires it to continue to implement and improve financial and land systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this integration and growth may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

**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.

**Non-Governmental Organizations**

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. The oil and natural gas industry has become increasingly politically polarizing in Canada, which has resulted in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. 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 the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects, which negative impact could prove to be material over time.

**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.

Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Corporation's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

**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 materially adversely affect the Corporation's business, financial condition, results of operations and prospects.

There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that the Corporation controls that, if successful or made into law, could impair our interests in the oil and natural gas properties that it controls and impact the Corporation's business, financial condition, results of operations and prospects.

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 Skilled Workforce and 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.

**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 (including, without limitation, exploration and development of lithium resource projects); 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.

**Limited Ability of Residents in the United States to Enforce Civil Remedies**

The Corporation is a corporation formed under the laws of Canada and has its principal place of business in Canada. All of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons may be located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Corporation or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

**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.

**Negative Impact of Additional Sales or Issuances of Common Shares**

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Corporation issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Corporation's securities could decline.

**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, 2022, 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, other than as follows:

1. Acquisition Agreement;
2. Agreement of Purchase and Sale dated March 22, 2023 in connection with the Rife Transaction;
3. SE Sask Acquisition Agreement;
4. Underwriting Agreement;
5. ACES Senior Loan Facility;
6. Warrant indenture dated March 4, 2022 with respect to the Note Warrants; and
7. 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, 2022