PRAIRIESKY ROYALTY

ANNUAL INFORMATION FORM

February 9, 2026

SIMPLIFIED ENERGY INVESTING

TSX | PSK

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Advisories

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form (*AIF*) contains forward-looking information and forward-looking statements (collectively, *forward-looking statements*). These forward-looking statements, which relate to future events or future performance, are provided to allow readers to better understand PrairieSky Royalty Ltd.'s (*PrairieSky* or the *Company*) business and prospects and may not be suitable for other purposes. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements include statements that are predictive in nature, depend upon or refer to future results, events or conditions, and include, but are not limited to, statements which are often, but not always, identified by the use of words such as seek, anticipate, plan, continue, estimate, expect, may, will, project, predict, potential, target, intend, could, might, should, believe and similar expressions (including the negatives thereof). Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in the forward-looking statements included in this AIF are reasonable, but actual results may differ materially from the forward-looking statements so no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These forward-looking statements speak only as of the date of this AIF. New factors emerge from time to time, and it is not possible for PrairieSky to predict all of these factors or to assess in advance the impact of each such factor on PrairieSky’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. The Company assumes no obligation to revise or update these forward-looking statements except as required pursuant to applicable securities laws.

In particular, and without limiting the foregoing, this AIF contains forward-looking statements pertaining to the following:

- the Company's objective to generate free cash flow and growth for its shareholders at a relatively low risk and low cost to the Company, and the proposed manner of achieving this objective;

- the Company's dividend policy, the funding of such dividends, the amounts expected to be paid under that policy in the future and the anticipated timing of payment of such dividends;

- the Company's business and growth strategy and the expectation that the Company will be successful in strategically seeking additional oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential;

- the expectation that the Company will be able to successfully encourage third parties to actively develop the Royalty Properties and the anticipation that only a small percentage of the Company’s undeveloped land holdings will expire within one year;

- the expectation that the Company will secure additional leasing and royalty arrangements with lessees, working interest owners and operators on the Royalty Properties;

- the estimated volumes and future net revenues related to the Company's oil and gas reserves and expectations regarding the ability of the Company to add to reserves through third-party development activities and acquisitions undertaken by the Company;

- projected oil and natural gas production levels and certain costs and expenses associated with the Royalty Properties;

- the Company's belief that there will be minimal or no operating costs, capital costs, environmental liabilities or reclamation obligations incurred by the Company related to oil and natural gas development on the Royalty Properties;
- the status, operational development and expected capacity of the Meadowbrook Project;
- the performance and characteristics of the Royalty Properties, including additional upside potential of many of the Royalty Properties, and the average royalty production volume contributions from the Royalty Properties including the impact of exploration and development activity, acquisitions and/or production declines;
- the timing and amount of capital expenditure programs and well drilling activity by third parties on the Royalty Properties;
- anticipated future crude oil, natural gas, NGL and other applicable commodity prices, and future currency exchange and interest rates;
- the expected development, completion and timing of infrastructure projects with respect to oil and natural gas transportation and processing, and the potential impacts thereof on the Canadian oil and gas industry;
- compliance with covenants under the Credit Facility until maturity;
- supply and demand for crude oil, natural gas, NGL and other applicable commodities;
- the primary sources of costs to the Company;
- the taxability of the Company and the ability to offset future taxable income;
- treatment under governmental regulatory regimes, environmental legislation and tax laws;
- opportunistic share repurchases and cancellations over time under PrairieSky's NCIB and specifically the volume and value of future repurchases under the current NCIB or future NCIBs based on current and forecasted funds from operations, the annual dividend rate and level of bank debt;
- the Company's plan to not enter into any commodity price or foreign exchange hedges; and
- the Company's expansive land position will provide diversification of exposure to producers and plays across Western Canada.

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

- the Royalty Properties will not be developed by third parties in the manner anticipated by the Company;
- non-compliance with lease or contractual royalty terms or payment or delivery delinquencies in respect of the Royalty Properties and associated production, including the credit risk associated with such third parties;
- third-party production companies' inability to manage inflationary cost pressures;
- volatility in the demand, supply and market prices for oil and natural gas products as well as other emerging marketable leased products;

- volatility in currency exchange and interest rates;
- long-term reliance on third parties as lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties;
- the timing of oil and natural gas projects being developed, sanctioned and commissioned, and the availability of egress capacity on such projects for any production from the Royalty Properties;
- risks and liabilities inherent in oil and natural gas operations as well as operations relating to other applicable commodities;
- the continuation or implementation of any tariffs, surtaxes or other restrictive trade measures or countermeasures affecting trade between Canada and the United States;
- uncertainties associated with estimating oil and gas reserves and future production levels;
- increased costs incurred by the Company or the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties;
- competition for, among other things, third-party capital and acquisitions of reserves, additional oil and natural gas assets and undeveloped lands;
- incorrect assessments of the value of assets and acquisitions by PrairieSky;
- changes in tax laws or royalty or incentive programs relating to the oil and natural gas industry;
- risks related to the environment and changing environmental laws and regulations in relation to the operations conducted on the Royalty Properties, including carbon pricing, future climate change regulations and regulations regarding Indigenous consultation and the resulting effects on the industry in general;
- geological, technical, drilling and completions, processing and handling issues (including deductions from PrairieSky's royalty share of production) associated with oil and natural gas development activities by third parties;
- claims made or legal actions brought or realized against the Company or its properties or assets;
- a failure by the Company to hire or retain key personnel;
- breaches or failure of information systems and security (including risks associated with cyber-attacks);
- a decrease or elimination of the payment of dividends by the Company as a result of a Board determination or restrictions under applicable agreements or corporate laws;
- general economic, market and business conditions; and
- the other factors discussed under "*Risk Factors*" herein.

Forward-looking statements are based on a number of factors and assumptions that have been used to develop such statements, but which may prove to be incorrect. Although PrairieSky believes that the assumptions underlying such forward-looking statements are reasonable, it can give no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur. In addition to other factors and assumptions that may be identified in this AIF, assumptions have been made regarding, among other things:

- the ability of the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties;

- the ability and willingness of the lessees on the Fee Lands and working interest owners on the Royalty Properties to comply with, and the Company to enforce, lease terms and contractual provisions, as applicable, in order to receive payments in respect of the Royalty Properties;

- the ability of the lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner;

- the timely receipt of any required regulatory approvals by lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties;

- the willingness and financial capability of the lessees on the Fee Lands and working interest owners on the GORR Lands to continue to develop and invest additional capital in the Royalty Properties;

- the ability of the lessees on the Fee Lands and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund exploration and development capital expenditures;

- field production rates, decline rates and the well performance and characteristics of the Royalty Properties;

- the ability to replace and increase oil and gas reserves and production associated with the Royalty Properties through third-party development and acquisitions;

- the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage;

- the ability of the operators of the properties in which the Company has a royalty interest in, to successfully market their respective crude oil, natural gas, NGL, and other applicable leased products or, for royalty payments taken-in-kind by the Company, if any, the ability of the Company or a third-party marketer to successfully market the Company's in-kind crude oil, natural gas, NGL and other applicable leased products;

- the Company not being responsible for any operating costs, capital costs, environmental liabilities, or abandonment and reclamation obligations associated with the development of oil and natural gas on the Royalty Properties by third-party operators;

- surface rights access being granted to third parties on the Royalty Properties;

- the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost-efficient manner;

- the absence of any material litigation or claims against the Company;

- the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company has an interest in oil and natural gas properties;

- the ability of the Company to mitigate the risks of fluctuations in commodity prices and production volumes;

- the ability of the Company to maintain compliance with financial covenants under the Credit Facility;

- commodity prices, including supply and demand factors relating to crude oil, natural gas and NGL, and specifically the effect of macroeconomic events on future commodity prices, royalty production volumes, revenues and cash flow; and

- currency exchange and interest rates.

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive and other factors could also adversely affect future results. The Company can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits PrairieSky will derive from them and such information may not be appropriate for other purposes. Readers are urged to consider these risks, as well as other uncertainties, factors and assumptions carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on such forward-looking statements, which are based only on information available to the Company as of the date of this AIF. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

GENERAL

Information contained in or otherwise accessible through the Company's website at www.prairiesky.com does not form a part of this AIF and is not incorporated into this AIF by reference unless expressly stated, including, for certainty and without limitation, PrairieSky's Sustainability Reports, Task Force on Climate-related Financial Disclosures Reports and 2025 CDP Corporate Questionnaire which are available on the Company's website at www.prairiesky.com, each of which are referred to in this AIF. Any other reports of the Company referred to herein are not incorporated by reference unless explicitly stated otherwise.

CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (*BOE*). PrairieSky uses the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (*6 Mcf = 1 bbl*). The 6:1 BOE ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the BOE ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio based on the current price of crude oil to natural gas is significantly different from the 6:1 energy equivalency ratio, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and gas reserves and other information with respect to the Royalty Properties in this AIF have been prepared and are presented in accordance with NI 51-101. See "*Reserves and Other Oil and Gas Information - Notes and Definitions*" for additional information.

All acreage information with respect to the Fee Lands, GRT Lands and GORR Lands in this AIF has been presented on a gross acre basis. For the Fee Lands, gross acres refers to the total percentage of undivided interest acres in which the Company holds fee simple mineral title and the associated mines and minerals rights. For the GRT Lands and GORR Lands, gross acres refers to the total acres related to the leasehold or title interests held by a third party in the lands on which the Company holds the GRT Interests or GORR Interests. Gross acres for the GRT Lands or GORR Lands do not account for the Company's net GRT Interests or GORR Interests percentage royalty ownership interest held in lands. Gross acreage for Crown Interest Lands is the acres covered by the lease and the net acres are the Company's working interest share of the gross acres. The presentation of gross acres for the Fee Lands, GRT Lands and GORR Lands is consistent with the presentation by certain of the Company's peers that hold a royalty interest on lands leased to or by third parties.

Glossary of Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms shall have the indicated meanings. Certain other terms used in this AIF but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. For additional definitions relating to oil and gas information (see "*Reserves and Other Oil and Gas Information — Notes and Definitions*"). Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

2026 Annual General Meeting means the annual general meeting of shareholders scheduled for April 20, 2026;

ABCA means the *Business Corporations Act* (Alberta) and the regulations thereunder, as amended from time to time;

affiliate or *associate* has the meaning ascribed thereto in the *Securities Act* (Alberta), as amended from time to time;

Board means the board of directors of the Company as it may be comprised from time to time;

CCUS means carbon capture, utilization and storage;

CNRL Parties means collectively, Canadian Natural Resources Limited, Canadian Natural Resources, Canadian Natural Resources Northern Alberta Partnership and CNR Royalty Partnership;

CNRL Royalty Acquisition means the acquisition by the Company from the CNRL Parties of (i) unleased Fee Lands; (ii) leased Fee Lands; and (iii) contractual royalties (including GORR Interests and GRT Interests) pursuant to the royalty assets purchase and sale agreement dated November 8, 2015, entered into between the CNRL Parties and the Company, as amended, pursuant to which the Company completed the CNRL Royalty Acquisition;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter) as amended from time to time;

Common Shares means the common shares in the capital of the Company;

CORRA means the Canadian Overnight Repo Rate Average;

Credit Facility means the Company's credit facility with a syndicate of Canadian banks, consisting of an unsecured extendible revolving credit facility and an unsecured extendible operating credit facility, as amended from time to time;

Crown Interest Lands means certain lands in which the Company holds or has acquired a lessee interest in a Crown oil and/or natural gas lease or licence, as more particularly detailed throughout this AIF, which are undeveloped with no wells, tangibles or other similar liability, and which the Company intends to sell or otherwise exchange for consideration of a GORR Interest;

EBITDA means earnings before interest, tax, depletion, depreciation and amortization;

Encana means Encana Corporation, which effective January 24, 2020 became Ovintiv Inc.;

Encana Purchase and Sale Agreement means the royalty business purchase and sale agreement dated May 22, 2014, entered into between Encana and the Company, pursuant to which the Company completed the Encana Royalty Acquisition;

Encana Royalty Acquisition means the acquisition by the Company from Encana of: (i) fee simple mineral title in lands prospective for oil, natural gas, NGL and certain other mineral rights located predominantly in central and southern Alberta; (ii) lessor interests in and to leases issued in respect of certain Fee Lands; (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments on lands located predominantly in Alberta; (iv) the Seismic Licence; and (v) certain other related assets as set forth in the Encana Purchase and Sale Agreement;

ESG means environmental, social and governance;

Fee Lands means lands prospective for oil, natural gas and certain other mines and minerals in which the Company holds a fee simple interest as more particularly detailed throughout this AIF;

GLJ means GLJ Ltd., independent qualified reserves evaluators;

GLJ Report means the independent engineering evaluation of the oil and gas reserves relating to the Royalty Properties prepared by GLJ with an effective date of December 31, 2025 and a preparation date of January 19, 2026;

GORR Interests means royalty and similar non-working interests (other than GRT Interests and Lessor Interests), including overriding royalty interests, gross overriding royalty interests, net profit interests and production payments on lands;

GORR Lands means certain lands in respect of which the Company holds GORR Interests as more particularly detailed throughout this AIF;

gross means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GORR Interests, GRT Interests; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area in which the Company has an interest;

GRT Interests means a trust or series of trusts settled by indenture or agreement which hold and collect, for the benefit of its unitholders, mineral interests and/or royalty payments in the form of lessor royalties;

GRT Lands means certain lands in which the Company holds GRT Interests as more particularly detailed throughout this AIF;

IPO means the initial public offering of the Company, pursuant to a secondary offering by Encana, completed on May 29, 2014, and resulting in the distribution by Encana of 52,000,000 Common Shares to the public, plus an additional 7,800,000 Common Shares on June 3, 2014, pursuant to the exercise of the over-allotment option granted by Encana to the underwriters of such offering;

Lessor Interests means lessor interests in and to leases that are currently issued in respect of certain Fee Lands;

Meadowbrook Project means the CCUS project being designed to provide CO_2 sequestration in which the Company is a minority joint venture partner;

Meadowbrook Project Operator means Bison Low Carbon Ventures Inc.;

net means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GRT Interests, GORR Interests in production or reserves, after deduction of royalty obligations payable to other parties, if any; (ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's Lessor Interest, GRT Interest or GORR Interest in each of its gross wells; and (iii) in relation to the Company's interest in a property, the total acreage in which the Company has an interest multiplied by the interest owned by the working interest owner of the Royalty Property;

NCIB means the Company's normal course issuer bid;

NGL means natural gas liquids, as such term is defined in NI 51-101;

NI 51-101 means *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities*;

NI 51-102 means *National Instrument 51-102 – Continuous Disclosure Obligations*;

OPEC+ means the Organization of Petroleum Exporting Countries;

persons means and includes individuals, companies, corporations, limited partnerships, general partnerships, joint stock companies, limited liability companies, joint ventures, associations, trusts, banks, trust companies, pension funds, and other organizations, whether or not legal entities, and governments and agencies and political subdivisions thereof;

Range GP means Range Royalty Management Ltd.;

Range Royalty means Range Royalty Limited Partnership;

Range Royalty Acquisition means the acquisition of all the issued and outstanding units of Range Royalty and all the issued and outstanding shares of Range GP by the Company effective December 19, 2014;

Reorganization means the internal reorganization involving Encana and the Company completed effective December 13, 2013, and the consolidation of Common Shares effective January 31, 2014;

Royalty Properties means collectively, the Fee Lands, the GORR Lands and the GRT Lands;

Secondary Offering means the secondary offering by Encana, pursuant to a short form prospectus of the Company, completed on September 26, 2014, and resulting in the distribution by Encana of 70,200,000 Common Shares to the public;

SEDAR+ means the System for Electronic Document Analysis and Retrieval +;

Seismic Licence means, as applicable to the context in this AIF, the irrevocable, perpetual, royalty-free, non-exclusive licence to certain proprietary seismic data of Encana, originally granted to the Company by Encana as part of the Encana Royalty Acquisition and pursuant to the Seismic Licence Agreement (*Encana*) and subsequently granted by the Seismic Licence Agreement (*SEI*);

Seismic Licence Agreement (Encana) means the agreement dated May 27, 2014, entered into between Encana and the Company, pursuant to which Encana granted the Seismic Licence to the Company;

Seismic Licence Agreement (SEI) means the agreement dated September 8, 2023, entered into between SEI Canada Seismic LLC (as successor in interest to Encana's proprietary seismic database) and the Company, pursuant to which SEI Canada Seismic LLC granted the Seismic Licence to the Company;

shareholder means a holder of Common Shares;

SOFR means the Secured Overnight Financing Rate;

subsidiary has the meaning ascribed thereto in the ABCA;

Tax Act means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time;

TSX means the Toronto Stock Exchange; and

working interest means the right granted to a lessee of a property to explore for and produce oil and/or natural gas on the leased lands, upon which such lessee bears the operating costs, capital costs, environmental liabilities and reclamation obligations associated with oil and natural gas development.

Abbreviations and Conversions

In this AIF, the following abbreviations have the meanings set forth below consistent with Appendix B of the COGE Handbook, where applicable. Certain other abbreviations and acronyms used in this AIF but not set forth below are to be given the meaning consistent with those in Appendix B of the COGE Handbook:

API	American Petroleum Institute
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcm	billion cubic meters
BOE	barrel of oil equivalent
BOE/d	barrels of oil equivalent per day
Mbbl	thousands of barrels
Mbbl/d	thousands of barrels per day
MBOE	thousands of barrels of oil equivalent
MBOE/d	thousands of barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet equivalent
MMBOE	million barrels of oil equivalent
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
M$	thousands of dollars

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units) consistent with Appendix C of the COGE Handbook:

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.292
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Corporate Structure

GENERAL

The Company was incorporated under the ABCA under the name "1786071 Alberta Ltd." on November 27, 2013. In December 2013 and January 2014, the Company undertook the Reorganization. On April 11, 2014, the Company changed its name to "PrairieSky Royalty Ltd." Prior to the completion of the IPO, the Company was a wholly-owned subsidiary of Encana.

On May 29, 2014, the Company completed the IPO and on September 26, 2014, the Company completed the Secondary Offering. Following the Secondary Offering, Encana no longer held any Common Shares.

On December 19, 2014, the Company acquired all of the issued and outstanding units of Range Royalty and all of the outstanding shares of Range GP in exchange for the issuance of approximately 19.3 million Common Shares. As part of the Range Royalty Acquisition and through a series of transactions: (i) Range Royalty was wound up and distributed its assets to PrairieSky; and (ii) PrairieSky amalgamated with Range GP and continued under the name "PrairieSky Royalty Ltd." PrairieSky is the legal successor in interest to Range Royalty and Range GP.

On November 8, 2017, PrairieSky amalgamated with its wholly-owned subsidiary, 2079323 Alberta Ltd., an immaterial subsidiary established for the sole purpose of acquiring certain royalty interests in Saskatchewan and on April 1, 2019, PrairieSky amalgamated with its wholly-owned subsidiary, MainSail Energy Ltd. PrairieSky is the legal successor in interest following each of these amalgamations.

As at December 31, 2025 and the date hereof, PrairieSky has no material subsidiaries.

The issued and outstanding Common Shares are listed and posted for trading on the TSX under the trading symbol "*PSK*". The location of the head and registered office of the Company is Suite 1700, 350 - 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

General Development of the Business

The following is a summary description of the development of PrairieSky's business for the three most recently completed financial years.

YEAR ENDED DECEMBER 31, 2025

PrairieSky reached record average annual oil royalty production of 13,940 barrels per day in 2025, an increase of 6% over 2024, with growth focused in the Duvernay light oil play and the Clearwater and Mannville heavy oil plays. During the year ended December 31, 2025, the Company entered into 189 leasing arrangements with 90 different counterparties, earning bonus consideration of $22.6 million. Leasing activity focused on oil targets across several plays and areas in Western Canada, including the Duvernay and Mannville heavy and light oil plays. The Company completed several royalty acquisitions during the year for aggregate consideration of $99.9 million, including the acquisition of fee lands, lessor interests and gross overriding royalty interests in Central Alberta and Southeast Saskatchewan from a private company for $50.4 million, after customary closing adjustments, which closed in January 2025. In 2025, the $45 million letter of credit provided to a third-party operator, as described under *General Development of the Business – Year Ended December 31, 2024,* was cancelled as a result of the third party operator securing its own funding due to the success of their capital program.

In July 2025, PrairieSky exercised the accordion feature of its unsecured, covenant-based Credit Facility with the existing syndicate of Canadian banks and entered into a first amending agreement, increasing the commitment of lenders by $250 million, bringing the aggregate credit limit available to PrairieSky to $600 million. There were no other amendments made to the Credit Facility. The expanded Credit Facility provides increased liquidity and financial flexibility moving forward. See *"Borrowings*".

The Company repurchased and cancelled an aggregate of 6,239,507 Common Shares pursuant to its NCIB during the fiscal year ended December 31, 2025 at a weighted average price of $25.40 per Common Share for aggregate consideration of approximately $158.5 million, including commissions and before tax.

YEAR ENDED DECEMBER 31, 2024

During the year ended December 31, 2024, the Company entered into 219 leasing arrangements with 101 different counterparties, earning bonus consideration of $30.8 million. Leasing activity focused on oil targets across several plays and areas in Western Canada, including the Duvernay and Mannville heavy and light oil plays. The Company completed several royalty acquisitions during the year for aggregate consideration of $57.3 million. Royalty acquisitions were focused on heavy and light oil plays across Alberta and Saskatchewan. The Company also provided a $45 million letter of credit (subject to reduction from time to time as agreed by the parties) to a third-party operator which secured its bank facility in order for the operator to advance its capital program targeting Montney oil on lands where PrairieSky has a royalty interest. The letter of credit was secured by a debenture over certain of the third-party operator's assets. The letter of credit was for a one-year term and could be extended for an additional one-year term at the option of the third-party operator. The letter of credit reduced the amount available to PrairieSky under its Credit Facility.

During 2024, the Company continued certain ESG and alternative energy initiatives, including receiving its first helium royalty revenues and its continued participation in the Meadowbrook Project. On July 30, 2024, the Meadowbrook Project Operator entered into a Carbon Sequestration Agreement with Alberta's Minister of Energy and Minerals. See "*Business of the Company – Governance, Sustainability and Corporate Responsibility*".

On December 18, 2024, PrairieSky entered into an amended and restated credit agreement in respect of the Credit Facility, voluntarily reducing it to $350 million from $725 million. The Credit Facility provides for a permitted increase up to $600 million, subject to lender consent. The sustainability-linked performance and pricing mechanisms under the previous credit facility were removed while all other covenants under the Credit Facility were unchanged from the previous credit facility. The Credit Facility matures on February 28, 2028. See "*Borrowings*".

YEAR ENDED DECEMBER 31, 2023

During the year ended December 31, 2023, the Company entered into 202 leasing arrangements with 110 different counterparties, earning bonus consideration of $26.0 million. Leasing activity focused on oil and natural gas targets across several plays and areas in Western Canada. The Company completed several acquisitions during the year for aggregate consideration of $58.4 million. Acquisitions focused on undeveloped land primarily in the Mannville, Clearwater and Banff oil plays as well as other emerging plays prospective for crude oil, NGL and natural gas.

During 2023, the Company's ESG and alternative energy initiatives included issuing work permits and leasing options for third parties to review helium opportunities and its participation in the Meadowbrook Project. The Meadowbrook Project Operator entered the final stages of completing the evaluation phase of the Meadowbrook Project under the Carbon Sequestration Evaluation Agreement with the Province of Alberta, which included testing of the suitability and capacity of the reservoir for CO_2 sequestration and operation of a carbon sequestration hub.

SIGNIFICANT ACQUISITIONS

The Company did not complete any acquisitions that would be considered significant pursuant to NI 51-102 during the year ended December 31, 2025.

Business of the Company

GENERAL

The Company currently has one of the largest independently owned portfolios of fee simple mineral title and oil and gas royalty interests in Canada. The Company is focused on encouraging third parties to actively develop the Royalty Properties while strategically seeking additional oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential, including the acquisition of Crown Interest Lands for purposes of complementing the Company's fee title land base and pursuing prospective farmout strategies. The Company does not conduct operations to explore for, develop or produce oil or natural gas; rather, third party development of the Royalty Properties provides the Company with royalty revenues as oil, natural gas and associated substances are produced from such properties. The Company's costs are primarily administrative expenses, corporate income taxes, and production and mineral taxes. Costs related to oil and natural gas upstream drilling, equipment, production and asset retirement obligations are not incurred by the Company; instead, these costs are incurred by the third parties who conduct activities on the Royalty Properties.

The Company's objective is to generate free cash flow and growth for its shareholders through indirect oil and natural gas investment at a relatively low risk and low cost to the Company. The Company strives to achieve this objective by: (i) focusing on organic growth of its royalty revenue from the Royalty Properties; (ii) proactively monitoring and managing its portfolio of Royalty Properties; (iii) generating efficiencies in its business and administration thereof, with a focus on managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders.

The Company's revenue stream is derived predominantly from royalties payable by lessees and working interest owners from oil and natural gas production on the Royalty Properties and revenues derived from related activities, including lease issuance bonus consideration and lease rentals. The Company actively pursues additional leasing and royalty arrangements with lessees and working interest owners and operators on the Royalty Properties and, from time to time, seeks to expand its portfolio of royalty interests through accretive acquisitions.

Overview of Royalties

Royalty ownership differs significantly from working interest ownership. A working interest owner is responsible for its share of operating costs, capital costs, environmental liabilities and reclamation obligations, usually in proportion to its ownership percentage, and it receives its pro rata share of revenue. A royalty owner enjoys the commercial benefit of hydrocarbon production and upside potential from a property, typically with no obligation for operating costs, capital costs, environmental liabilities or reclamation obligations.

The Company's royalty revenues are derived predominantly from: (i) the Lessor Interests on the Fee Lands leased out by the Company and upon which lessees pay lessor royalties to the Company; (ii) the GORR Lands leased by third parties upon which such third parties pay the Company overriding royalties, net profit, production or such other similar forms of royalty encumbrances; (iii) the GRT Lands; and (iv) related activities, including lease issuance bonus consideration and lease rentals on the Fee Lands.

The Company does not conduct any drilling activity and is not responsible for making any capital expenditures with respect to the Royalty Properties. The Company receives royalty revenue based on the production performance of wells, with the calculation of such royalty revenues payable based, in part, on the market price of oil and/or natural gas and allowances, if any, for certain deductions. Through certain contractual arrangements with third parties, the Company is able to receive its royalty percentage share of production from the Royalty Properties as a physical or "in-kind" delivery of hydrocarbons. The Company currently takes certain crude oil royalty volumes in-kind.

Lessor Interests

The Company derives a portion of its royalty revenue from Lessor Interests in respect of producing wells located on the Company's approximately 9.9 million acres of Fee Lands. For the year ended December 31, 2025, the Lessor Interests provided approximately 62% of the total royalty revenue of the Company, of which royalty revenue derived from production of liquids (crude oil and NGL) and natural gas accounted for approximately 94% and 6%, respectively.

For the year ended December 31, 2025, average net production associated with the Lessor Interests was 14,664 BOE/d, comprised of 8,460 bbl/d of crude oil production, 28.6 MMcf/d of natural gas production and 1,437 bbl/d of NGL production, generating total royalty revenue of $273.5 million. In addition, in 2025, lease rental income associated with the Lessor Interests was $7.4 million and lease issuance bonus consideration was $22.6 million.

GORR Interests

The GORR Lands are governed by contractual arrangements whereby a royalty interest has been reserved out of the working interest production and granted to the Company. The Company receives gross overriding royalties calculated as a share of hydrocarbons produced from the applicable lands. Typically, GORR Interests expire upon the termination of the underlying leases or licences if they are not developed or, where the GORR Lands have been developed and production activity has ceased, well abandonment activities have taken place and the corresponding leases or licences have been surrendered. GORR Interests are typically legal interests in land that run with the GORR Lands in the event the underlying lease is continued or transferred. Under some contractual arrangements, replacement leases may be contemplated by the applicable contract, thereby extending the application of the GORR Interests. Under other contractual arrangements, acquired leases and licences within a geographic area, typically known as an "Area of Mutual Interest", may become governed by the contract.

The granting of a GORR Interest can arise in many instances, including as a result of: (i) the Company farming out working interest rights to another company in exchange for retaining a GORR Interest on production from wells drilled on such lands; (ii) the Company providing capital in exchange for granting of a GORR Interest or converting a participating interest in a joint venture relationship into a GORR Interest; (iii) the Company, as owner of certain Fee Lands that are in a checkerboard pattern, receiving a GORR Interest on offsetting Crown acreage, achieved in exchange for allowing drilling by third parties of longer horizontal wells across sections that include portions of the Fee Lands or in certain cases where a third party has reviewed the Company's seismic data and acquired a lease or licence in respect of the underlying Crown mineral rights; or (iv) various other contractual arrangements.

The Company holds GORR Interests in approximately 8.4 million acres of GORR Lands, substantially all of which are associated with Crown lands. During the year ended December 31, 2025, average net production associated with the GORR Lands was 11,191 BOE/d, comprised of 27.9 MMcf/d of natural gas production, 5,480 bbl/d of crude oil production and 1,061 bbl/d of NGL production, generating total royalty revenue of $168.2 million. In 2025, the GORR Interests provided approximately 38% of the total royalty revenue of PrairieSky.

GRT Interests

The Company holds approximately 0.3 million acres of GRT Lands. The GRT Interests are governed under trustee arrangements made with financial institutions and are held by virtue of trust unit certificates issued by the financial institution to the unitholders. Each trust unit represents a fractional ownership share of the lessor royalty percentage payable out of the mines and minerals fee title interests in the GRT Lands when leases are granted, and in rare instances, may be a fractional ownership of a fee title.

Crown Interest Lands

The Company holds approximately 9,500 acres of Crown Interest Lands predominantly in Alberta which were acquired to complement the Company's Fee Lands and to build land positions in strategic areas for purposes of royalty interest transactions.

SPECIALIZED SKILLS AND KNOWLEDGE

The Company relies on specialized skills and knowledge to manage the Royalty Properties. The Company employs a strategy of contracting a limited number of consultants and other specialized service providers to supplement the skills and knowledge of its permanent staff in order to manage the Company's business effectively. PrairieSky also strives to be the best by exploring and employing new technology platforms to maximize efficiencies in managing the Royalty Properties and ensuring a best-in-class compliance program.

REORGANIZATIONS

There have been no material reorganizations of the Company since January 1, 2023 and none are proposed for the current financial year.

PERSONNEL

As of December 31, 2025, the Company had 70 full-time employees and 1 part-time employee.

COMMODITY PRICES

PrairieSky's operational results and financial condition are dependent on the prices received for oil and natural gas production. Benchmark oil and natural gas prices are determined by supply and demand, which can be impacted by many factors, including weather and general economic conditions, as well as egress and processing constraints and conditions in other oil and natural gas regions. Canadian crude oil, natural gas and NGL can also be affected by regional factors which may result in significant pricing discounts relative to global benchmark prices. Declines in commodity prices adversely affect PrairieSky's business and financial condition. See "*Risk Factors – Commodity Prices, Markets and Marketing*".

CYCLICAL AND SEASONAL NATURE OF INDUSTRY

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. Also, certain oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to variability in exploration and production activity during certain parts of the year and corresponding variability in production from the Royalty Properties.

ENVIRONMENTAL CONSIDERATIONS

PrairieSky relies on the lessees and/or operators of the Royalty Properties to be in compliance with current environmental rules and regulations set by the provincial and federal governments in Canada. Failure to comply with environmental regulations could result in the imposition of material fines or penalties on the working interest owners and/or the operators or the curtailment of production which may negatively impact the Company's business and financial condition, which negative impact could prove to be material over time.

COMPETITIVE CONDITIONS

PrairieSky's business is tied to the oil and natural gas industry, which is highly competitive at all levels. Although PrairieSky does not drill wells, own facilities or operate oil and gas assets, it competes with other companies for certain business inputs, access to commodity markets, acquisition opportunities, available capital and staffing. PrairieSky strives to be competitive by maintaining a strong financial condition, focusing on building and maintaining strong relationships with high quality lessees, and identifying new geological plays and ways to enhance development and recovery of hydrocarbons to maximize the value on the Royalty Properties. Management believes that the Company's land ownership structure, and a weighting towards fee simple mineral title ownership, provides a significant competitive advantage compared to other royalty companies.

GOVERNANCE, SUSTAINABILITY AND CORPORATE RESPONSIBILITY

Our core values define what is important to us and are at the foundation of how PrairieSky carries on business. While PrairieSky does not operate, develop or produce any oil and gas assets on the Royalty Properties, PrairieSky recognizes its business model is dependent on the industry operating in a responsible fashion and it is committed to conducting its business in a sustainable and responsible manner. By conducting its business responsibly, actively managing risk and upholding the highest standards of governance and ethics, PrairieSky aims to provide long-term shareholder and stakeholder value. The Company approaches its relationships with all stakeholders with integrity and respect, and PrairieSky takes care to select operators that share its core values. Because of the long duration of PrairieSky's assets, successful execution of this strategy is only possible if the Company's lands are developed ethically and responsibly. A detailed description of PrairieSky's corporate reporting initiatives and a discussion of ESG issues is contained in PrairieSky's 2024 Sustainability Report, which can be found on the Company's website at www.prairiesky.com but is not to be considered part of or incorporated into this AIF. PrairieSky's 2025 CDP Corporate Questionnaire as well as prior year Task Force on Climate-related Financial Disclosures can be found on the Company's website at www.prairiesky.com.

PrairieSky has adopted policies relating to its business conduct, including a business code of conduct, a supplier code of conduct, an investigations practice policy, a disclosure policy, a securities trading and insider reporting policy, a restricted securities trading policy, a human rights policy (as PrairieSky supports the Ten Principles of the United Nations Global Compact with respect to human rights, labour, environment and anti-corruption), a respectful workplace policy, a shareholder engagement policy, an environment, climate change, health and safety policy, a board renewal policy and a board diversity policy. Summaries of certain key policies will be included in the Company's management information circular and proxy statement for the 2026 Annual General Meeting, while additional information on these and other policies can be found on the Company's website at www.prairiesky.com. A copy of PrairieSky's annual Communication on Progress in relation to the UN Global Compact is included in the Company's 2024 Sustainability Report which is available on the Company's website at www.prairiesky.com.

PrairieSky has advanced several of its ESG and alternative energy initiatives having issued a large-scale lithium exploration lease in Saskatchewan and various helium leasing arrangements in Alberta, some of which have achieved commercial production. In addition, on December 9, 2025 the Meadowbrook Project Operator announced completion of commissioning operations of the Phase 1 facility at the Meadowbrook Carbon Storage Hub, making it the first Alberta Carbon Capture and Storage Hub project to enter service.

PrairieSky maintained its "AAA" rating and "Leader" MSCI ESG Risk Rating status in 2025. PrairieSky is a constituent of the “Dow Jones Best-in-Class World Index” as assessed through S&P's Global Corporate Sustainability Assessment. PrairieSky was ranked #1 out of 277 global oil and gas producers by Sustainalytics, with a "Negligible Risk," as of February 6, 2026. These results demonstrate the Company's ongoing commitment to environmental stewardship, social responsibility, and governance.

Reserves Data and Other Oil and Gas Information

DISCLOSURE OF RESERVES DATA

In accordance with NI 51-101, the reserves data associated with the Royalty Properties set forth below is based upon an evaluation prepared by GLJ with an effective date of December 31, 2025, and preparation date of January 19, 2026. The GLJ Report evaluated the oil and gas reserves associated with the Royalty Properties as at December 31, 2025. The tables below summarize the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the GLJ Report based on the arithmetic average of the standard price forecasts from three leading Canadian oil and gas evaluation consulting firms (GLJ, McDaniel & Associates Consultants Ltd., and Sproule Associates Limited) effective January 1, 2026.

The tables summarize the data contained in the GLJ Report and as a result, may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the reserves is stated without provision for interest costs and administrative costs, but after providing for estimated royalties and production and mineral taxes. Future net revenues are presented on a before- and after-tax basis. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by GLJ represents the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. There can be no assurance that such price and cost assumptions will be attained and variances could be material. Other assumptions have been made by GLJ and qualifications related to the costs and other matters are included in the GLJ Report. The recovery estimates of the reserves provided herein are estimates only and there is no guarantee that the reserves, as estimated, will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

In preparing the GLJ Report, GLJ relied on certain information provided by third parties associated with the Royalty Properties, which included working and net revenue interest data, public data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, financial data and future development and operating plans for the Royalty Properties, as applicable. Other engineering, historical production, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based was obtained from public records and from non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The Report on Reserves Data by GLJ in Form 51-101F2 for each of the GLJ Report and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this AIF as Appendix A and Appendix B, respectively.

GLJ was engaged by the Company to provide an evaluation of proved and probable reserves. All of the reserves associated with the Royalty Properties are located in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba. **As the Company does not hold any working interests in the Royalty Properties, the Company is not responsible for any capital costs associated with the Royalty Properties and, as such, the evaluation of reserves data does not include any undeveloped reserves.**

Reserves Data as of December 31, 2025 Forecast Prices and Costs[1]

Summary of Reserves

Reserves Category	Light and Medium Crude Oil Gross (2)(4) (Mbbl)	Light and Medium Crude Oil Net (3)(4) (Mbbl)	Heavy Crude Oil Gross (2)(4) (Mbbl)	Heavy Crude Oil Net (3)(4) (Mbbl)	Tight Oil Gross (2)(4) (Mbbl)	Tight Oil Net (3)(4) (Mbbl)	Bitumen Gross (2)(4) (Mbbl)	Bitumen Net (3)(4) (Mbbl)	Conventional Natural Gas Gross (2)(4) (MMcf)	Conventional Natural Gas Net (3)(4) (MMcf)
Proved										
Developed Producing	-	8,648	-	8,712	-	1,175	-	1,224	-	97,326
Developed Non-Producing	-	271	-	562	-	136	-	184	-	1,962
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	8,919	-	9,274	-	1,311	-	1,407	-	99,288
Total Probable	-	2,191	-	4,090	-	509	-	672	-	16,601
Total Proved Plus Probable	-	11,110	-	13,364	-	1,821	-	2,080	-	115,890

** Numbers may not add due to rounding.*

Reserves Category	Shale Gas Gross (2)(4) (MMcf)	Shale Gas Net (3)(4) (MMcf)	Coal Bed Methane Gross (2)(4) (MMcf)	Coal Bed Methane Net (3)(4) (MMcf)	Natural Gas Liquids Gross (2)(4) (Mbbl)	Natural Gas Liquids Net (3)(4) (Mbbl)	Total Oil Equivalent Gross (2)(4) (MBOE)	Total Oil Equivalent Net (3)(4) (MBOE)
Proved								
Developed Producing	-	18,060	-	26,698	-	5,045	-	48,484
Developed Non-Producing	-	250	-	-	-	58	-	1,580
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	18,310	-	26,698	-	5,103	-	50,064
Total Probable	-	6,321	-	9,323	-	1,031	-	13,868
Total Proved Plus Probable	-	24,631	-	36,022	-	6,135	-	63,932

** Numbers may not add due to rounding.*

Notes:

(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".

(2) Gross reserves represent the Company's interest in reserves before deduction of royalties and without including any royalty interests.

(3) Net reserves represent the Company's interest in reserves after deduction of royalty obligations plus the Company's royalty interests in reserves.

(4) The Company differs from typical oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the oil and natural gas industry.

Summary of Net Present Values of Future Net Revenue

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)(1) 0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Income Tax Discounted at 10%/year(2) $/BOE	$/Mcfe
Proved							
Developed Producing	2,310,967	1,759,439	1,429,282	1,210,960	1,056,241	29.48	4.91
Developed Non-Producing	98,681	81,581	70,270	62,224	56,190	44.48	7.41
Undeveloped	-	-	-	-	-	-	-
Total Proved	2,409,648	1,841,020	1,499,551	1,273,184	1,112,431	29.95	4.99
Total Probable	874,258	506,690	341,764	253,315	199,704	24.64	4.11
Total Proved Plus Probable	3,283,906	2,347,710	1,841,315	1,526,499	1,312,135	28.80	4.80

** Numbers may not add due to rounding.*

	Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)[1]				
	0%	5%	10%	15%	20%
Reserves Category	**M$**	**M$**	**M$**	**M$**	**M$**
Proved					
Developed Producing	2,028,272	1,530,191	1,236,156	1,043,579	908,016
Developed Non-Producing	75,671	62,481	53,806	47,653	43,046
Undeveloped	-	-	-	-	-
Total Proved	2,103,943	1,592,672	1,289,962	1,091,233	951,062
Total Probable	677,617	388,690	261,126	193,236	152,226
Total Proved Plus Probable	2,781,560	1,981,362	1,551,087	1,284,468	1,103,288

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Unit values are based on Company net reserves.

Additional Information Concerning Future Net Revenue (Undiscounted) as of December 31, 2025

Reserves Category	Revenue[1]	Royalties[2]	Operating Costs[3]	Capital Development Costs[3]	Aband. & Recl. Costs[3]	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	M$	*M$*	*M$*	*M$*	*M$*	*M$*	*M$*	*M$*
Proved								
Developed Producing	2,323,720	12,753	-	-	-	2,310,967	282,696	2,028,272
Developed Non-Producing	99,191	510	-	-	-	98,681	23,010	75,671
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	2,422,911	13,263	-	-	-	2,409,648	305,705	2,103,943
Total Probable	878,935	4,677	-	-	-	874,258	196,641	677,617
Total Proved Plus Probable	3,301,846	17,940	-	-	-	3,283,906	502,346	2,781,560

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Production and mineral taxes payable.
(3) The Company does not hold any working interests in the Royalty Properties. As such, the Company is not responsible for any operating, development or abandonment and reclamation costs associated with estimated net revenues from the reserves attributed to the Royalty Properties.

Future Net Revenue by Production Type as of December 31, 2025 – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes[1][2] (Discounted at 10%/year)		
	M$	$/BOE	$/Mcfe
Proved Producing			
Light Crude Oil & Medium Crude Oil (combined)[3]	520,876	43.32	7.22
Heavy Crude Oil[3]	430,033	46.15	7.69
Tight Oil[3]	67,659	41.05	6.84
Bitumen[3]	67,368	54.02	9.00
Conventional Natural Gas[4]	217,514	13.37	2.23
Shale Gas[4]	70,069	19.88	3.31
Coal Bed Methane	55,763	12.51	2.09
Total Proved Producing	1,429,282	29.48	4.91
Total Proved			
Light Crude Oil & Medium Crude Oil (combined)[3]	538,854	43.64	7.27

	Future Net Revenue Before Income Taxes(1)(2) (Discounted at 10%/year)		
	M$	$/BOE	$/Mcfe
Heavy Crude Oil(3)	460,842	46.48	7.75
Tight Oil(3)	76,184	41.50	6.92
Bitumen(3)	76,400	53.36	8.89
Conventional Natural Gas(4)	221,442	13.38	2.23
Shale Gas(4)	70,066	19.88	3.31
Coal Bed Methane	55,763	12.51	2.09
Total Proved	1,499,551	29.95	4.99
Total Proved Plus Probable			
Light Crude Oil & Medium Crude Oil (combined)(3)	633,610	41.20	6.87
Heavy Crude Oil(3)	608,482	42.54	7.09
Tight Oil(3)	97,407	38.41	6.40
Bitumen(3)	106,736	50.54	8.42
Conventional Natural Gas(4)	239,861	12.75	2.12
Shale Gas(4)	87,001	18.24	3.04
Coal Bed Methane	68,218	11.35	1.89
Total Proved Plus Probable	1,841,315	28.80	4.80

**Numbers may not add due to rounding.*

Notes:

(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".

(2) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company net reserves.

(3) Including solution gas and other by-products.

(4) Including by-products but excluding solution gas.

For future net revenue of the total proved reserves before income taxes, discounted at 10%, 77% of the revenue is from combined crude oil and 23% is from combined natural gas. For the total proved plus probable reserves, 79% of the future net revenue before income taxes, discounted at 10%, is from combined crude oil and 21% is from combined natural gas.

NOTES AND DEFINITIONS

In the tables set forth above and elsewhere in this AIF, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods are required to properly use and apply reserves definitions.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- within specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories may be divided into developed and undeveloped categories.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities, or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation is based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities", which refers to the lowest level at which reserves calculations are performed, and to "reported reserves", which refers to the highest level sum of individual entity estimates for which reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

PRICING ASSUMPTIONS — FORECAST PRICES AND COSTS

GLJ employed the following then current pricing, inflation rate and exchange rate assumptions based on the arithmetic average of the standard price forecasts from three leading Canadian oil and gas evaluation consulting firms (GLJ, McDaniel & Associates Consultants Ltd. and Sproule Associates Limited) effective January 1, 2026.

	Crude Oil						
Year	**WTI Cushing, Oklahoma**	**Edmonton Par Price 40° API**	**Hardisty Cold Lake 21.3° API**	**Hardisty Western Canadian Select**	**Hardisty Heavy Oil 12° AP**	**Cromer Light Sour 35° API**	**Exchange Rate(1)**
	($US/bbl)	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($US/$Cdn)***
2026	59.92	77.54	63.48	65.12	60.09	76.59	0.728
2027	65.10	83.60	69.25	70.43	64.94	82.58	0.737
2028	70.28	90.18	75.19	76.90	71.16	89.09	0.740
2029	71.93	92.32	77.10	78.71	72.84	91.20	0.740
2030	73.37	94.17	78.64	80.29	74.30	93.03	0.740
2031-2035	77.90	99.97	83.49	85.24	78.90	98.76	0.740
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year

	Natural Gas	**Alberta Natural Gas Liquids**				
Year	**AECO/NIT Spot**	**Spec Ethane**	**Edmonton Propane**	**Edmonton Butane**	**Edmonton Pentane Plus**	**Inflation Rate(2)**
	($/MMbtu)	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***(%/year)***
2026	3.00	9.59	25.10	36.95	80.01	0.00
2027	3.30	10.64	27.28	39.79	86.19	2.00
2028	3.49	11.34	29.67	42.87	92.83	2.00
2029	3.58	11.66	30.37	43.89	95.05	2.00
2030	3.65	11.89	30.98	44.77	96.94	2.00
2031-2035	3.88	12.65	32.89	47.53	102.92	2.00
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year

Notes:

(1) Exchange rates used to generate Canadian benchmark reference prices in this table.
(2) Inflation rates for forecasting.

During 2025, average sales prices realized in respect of the production associated with the Royalty Properties were $1.39/Mcf for natural gas, $74.34/bbl for crude oil and $38.21/bbl for NGL.

RESERVES RECONCILIATION

A requirement of NI 51-101 is the provision of a reconciliation on a gross reserves basis. Due to the Company's unique asset base, the tables setting forth the reconciliation of gross reserves do not provide adequate information and are potentially misleading. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As substantially all of the Company's assets are royalty interests, they would be excluded in a gross reconciliation table. The Company believes this would hinder an investor's ability to compare PrairieSky's reserves to others in the same industry.

The following reserve reconciliation table is provided as an aid to the reader. The table is based on net reserves and is consistent with disclosure presented by other entities in the royalty business.

Reconciliation of Company Net Reserves by Principal Product Type – Forecast Prices and Costs

	Light and Medium Crude Oil			**Heavy Crude Oil**		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbl)	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***
December 31, 2024	8,666	2,631	11,297	8,497	3,058	11,555
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	1,207	506	1,713	1,821	1,101	2,922
Technical Revisions	960	(957)	3	1,084	(39)	1,045
Acquisitions	380	76	456	21	3	24
Dispositions	-	-	-	-	-	-
Economic Factors	(198)	(66)	(263)	(72)	(33)	(105)
Production	(2,097)	-	(2,097)	(2,077)	-	(2,077)
December 31, 2025	8,919	2,191	11,110	9,274	4,090	13,364

	Tight Oil			**Bitumen**		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbl)	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***
December 31, 2024	1,238	439	1,677	1,514	577	2,091
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	394	171	564	262	150	412
Technical Revisions	72	(95)	(23)	173	(50)	123
Acquisitions	1	-	1	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(15)	(5)	(19)	(6)	(5)	(11)
Production	(379)	-	(379)	(536)	-	(536)
December 31, 2025	1,311	509	1,821	1,407	672	2,080

	Conventional Natural Gas			**Shale Gas**		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	***(MMcf)***	***(MMcf)***	***(MMcf)***	***(MMcf)***	***(MMcf)***
December 31, 2024	91,191	26,235	117,426	18,026	6,110	24,135
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	3,391	1,797	5,188	3,042	1,242	4,284
Technical Revisions	19,790	(11,355)	8,435	554	(1,002)	(448)
Acquisitions	1,702	255	1,957	22	-	22
Dispositions	-	-	-	-	-	-
Economic Factors	(2,562)	(330)	(2,891)	(60)	(30)	(90)
Production	(14,225)	-	(14,225)	(3,273)	-	(3,273)
December 31, 2025	99,288	16,601	115,890	18,310	6,321	24,631

	Coal Bed Methane			**Natural Gas Liquids**		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	***(MMcf)***	***(MMcf)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***
December 31, 2024	33,830	8,060	41,890	4,945	1,512	6,458
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	264	115	378
Technical Revisions	(4,340)	1,206	(3,134)	842	(598)	244
Acquisitions	350	69	419	40	6	46
Dispositions	-	-	-	-	-	-
Economic Factors	(2)	(12)	(13)	(76)	(4)	(80)
Production	(3,140)	-	(3,140)	(912)	-	(912)
December 31, 2025	26,698	9,323	36,022	5,103	1,031	6,135

	Total Oil Equivalent		
	Proved	**Probable**	**Proved Plus Probable**
	(MBOE)	***(MBOE)***	***(MBOE)***
December 31, 2024	48,701	14,952	63,653
Discoveries	-	-	-
Extensions & Improved Recovery	5,019	2,549	7,568
Technical Revisions	5,798	(3,598)	2,200
Acquisitions	788	139	927
Dispositions	-	-	-
Economic Factors	(803)	(175)	(978)
Production	(9,439)	-	(9,439)
December 31, 2025	50,064	13,868	63,932

**Numbers may not add due to rounding.*

As of December 31, 2025, PrairieSky's total proved plus probable reserves were 63,932 MBOE, with reserve additions from extensions and improved recovery replacing approximately 80% of production. Drilling extensions added 6,450 MBOE of proved plus probable reserves, mainly driven by development in the Clearwater, Duvernay, and Mannville oil plays, contributing to a 7% increase in proved plus probable oil reserves. The continued expansion of secondary recovery through waterflooding in the Clearwater contributed to improved recovery additions totaling 1,118 MBOE of proved plus probable reserves. Net technical revisions of 2,200 MBOE in proved plus probable reserves were spread across multiple zones, with positive revisions in the Clearwater and Glauconitic formations. Economic factors led to a reduction of 978 MBOE proved plus probable reserves due to lower forecast commodity pricing. Acquisitions contributed an incremental 927 MBOE of proved plus probable reserves additions, weighted towards Madison Group properties (SE Saskatchewan).

Overall, total proved reserves volumes increased by 3%, as contributions from third-party operator drilling, improved recovery, acquisitions, and net positive technical revisions were partially offset by production and economic factors. Total proved plus probable reserves volumes increased by 0.4%, with production and economic factors largely offsetting the gains from third-party operator drilling, improved recovery factors, acquisitions, and net positive technical revisions.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The reserves were evaluated by GLJ who is an independent qualified reserves evaluator.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing economic or regulatory environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative. See "*Risk Factors – Reserves Estimates*".

FUTURE DEVELOPMENT COSTS

Funding for development costs is the responsibility of the working interest owners on the applicable properties. The Company does not hold any oil and natural gas working interests in the Royalty Properties and is not responsible for any oil and natural gas development costs on the Royalty Properties. No future development capital is considered in the Company's reserve evaluation and the Company cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

OIL AND NATURAL GAS PROPERTIES AND WELLS

The following tables summarize the gross number of oil and natural gas wells located on the Royalty Properties in which the Company holds a royalty interest, all of which are located in British Columbia, Alberta, Saskatchewan and Manitoba, and all of which are onshore. As the Company does not hold any oil and natural gas working interests in the Royalty Properties or related infrastructure, the net number of wells, or ownership in properties or facilities located on the Royalty Properties is nil.

	Natural Gas[1]		Oil[1]	
Area	**Producing**	**Non-Producing[2]**	**Producing**	**Non-Producing[2]**
Alberta	19,334	-	8,087	-
Saskatchewan	5,328	-	7,761	-
British Columbia	296	-	23	-
Manitoba	2	-	1,062	-

Notes:

(1) Includes unit wells.

(2) Royalty revenues payable by third parties are based on oil and natural gas producing wells located on the Royalty Properties. The Company does not have information from third parties on non-producing oil and natural gas wells located on the Royalty Properties.

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table summarizes the undeveloped land holdings of the Company with no attributed reserves as at December 31, 2025 and the acreage which is subject to a lease term expiry within one year.

	Fee Lands[1][2]	GRT Lands[1][2]	GORR Lands[3][4]		Crown Interest Lands[3][4]		
(thousands of acres)	**Gross Acres**	**Gross Acres[3]**	**Gross Acres**	**Gross Acres expiring within one year**	**Gross Acres**	**Net Acres**	**Net Acres expiring within one year**
Alberta	4,832	70	2,973	136	11	11	4
Saskatchewan	1,548	86	349	7	1	1	-
British Columbia	-	1	311	9	-	-	-
Manitoba	693	6	1	-	-	-	-
Other	1	-	63	-	-	-	-
Total	7,074	163	3,697	152	12	12	4

** Numbers may not add due to rounding.*

Notes:

(1) Fee lands with multiple leases under the same surface area have been calculated on an aerial basis, and as such have only been counted once.

(2) The oil and/or natural gas rights associated with certified title to Fee Lands and GRT Lands under superior trust agreements are held in perpetuity. The number of uncertified titles and inferior trust agreements held by the Company are *de minimus*. As such, there is no meaningful number of gross acres for which the Company's interests will expire during 2026.

(3) Undeveloped lands are calculated by adding the surface area covered by individual leases or agreements. In certain limited circumstances where the Company holds interests under the same surface area pursuant to different leases or agreements, the acreage with respect to all such leases or agreements are added together.

(4) Some of this acreage may qualify to be continued by the working interest owners pursuant to other operations on the lands or offsetting lands as allowed by the regulations. Additionally, although the Company does not directly conduct operations on these lands, it makes reasonable efforts to have third parties actively develop the lands prior to lease expiries and therefore anticipates only a small percentage of this acreage to expire during this period. There are no significant factors or uncertainties associated with the undeveloped land holdings.

TAX HORIZON

The Company is presently cash taxable. The statutory corporate income tax rate applicable to the Company in 2025 was approximately 23.5% and the Company recognized current income taxes of $59.5 million in net earnings. A corporation's taxable income is based on total revenue, expenses and other deductions, which in the case of the Company will vary depending on the amount of royalty revenue received as a result of fluctuations in commodity prices and development activities on the properties in which it holds interests, as well as other revenues related to leasing activity on Fee Lands. At December 31, 2025, the Company had $1.2 billion of tax pools which can be used to offset future taxable income.

COSTS INCURRED

The following table sets out the Company's property acquisition costs and seismic acquisition costs for the year ended December 31, 2025.

Expenditures	**Year Ended December 31, 2025 ($millions)**
Property Acquisition Costs:	
Proved Properties	41.1
Unproved Properties	56.2
Seismic Acquisitions	2.6
Total	99.9

PRODUCTION ESTIMATES

The following table discloses for each product type the gross and net volume of production estimated by GLJ for the year ended December 31, 2026, in the estimates of gross and net proved and gross and net probable reserves disclosed above under the heading "*Reserves and Other Oil and Gas Information — Disclosure of Reserves Data*".

	Light and Medium Crude Oil		**Heavy Crude Oil**		**Tight Oil**		**Bitumen**	
Reserves Category	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**
	(bbl/d)		***(bbl/d)***		***(bbl/d)***		***(bbl/d)***	
Proved								
Developed Producing	-	4,314	-	4,548	-	669	-	1,056
Developed Non-Producing	-	271	-	387	-	107	-	159
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	4,586	-	4,936	-	776	-	1,215
Total Probable	-	217	-	504	-	90	-	162
Total Proved Plus Probable	-	4,802	-	5,440	-	866	-	1,377

	Conventional Natural Gas		**Shale Gas**		**Coal Bed Methane**		**NGL**	
Reserves Category	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**	**Gross(1)(2)**	**Net(3)**
	(Mcf/d)		***(Mcf/d)***		***(Mcf/d)***		***(Bbl/d)***	
Proved								
Developed Producing	-	33,769	-	7,785	-	8,355	-	1,939
Developed Non-Producing	-	775	-	173	-	-	-	28
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	34,544	-	7,958	-	8,355	-	1,967
Total Probable	-	1,201	-	580	-	201	-	71
Total Proved Plus Probable	-	35,745	-	8,538	-	8,556	-	2,039

	Total Oil Equivalent	
Reserves Category	**Gross(1)(2)**	**Net(3)**
	(BOE/d)	
Proved		
Developed Producing	-	20,845
Developed Non-Producing	-	1,111
Undeveloped	-	-
Total Proved	-	21,956
Total Probable	-	1,375
Total Proved Plus Probable	-	23,331

** Numbers may not add due to rounding.*

Notes:

(1) Gross production represents the Company's interest in production before deduction of royalties and without including any royalty interests.

(2) The Company differs from oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the oil and natural gas industry.

(3) Net production represents the Company's interest in production after deduction of royalty obligations plus the Company's royalty interests in production.

PRODUCTION HISTORY

The following table summarizes production, product prices received, royalties paid (production and mineral tax expense), cash administrative expenses and resulting operating netback for the periods indicated below.

		2025			
	Annual 2025	**Q4**	**Q3**	**Q2**	**Q1**
Average daily production(1)					
Natural Gas *(MMcf/d)*	56.5	55.8	56.1	58.4	55.9
Crude Oil *(bbl/d)*	13,940	13,750	14,127	14,376	13,502
NGL *(bbl/d)*	2,498	2,915	2,210	2,348	2,520
Total *(BOE/d)*	25,855	25,965	25,687	26,457	25,339
Average price realized(2)					
Natural Gas ($/*Mcf*)	1.39	1.85	0.48	1.50	1.73
Crude Oil *($bbl)*	74.34	66.10	75.30	73.16	83.16
NGL *($bbl)*	38.21	36.51	36.29	35.47	44.51
Total ($/*BOE)*	46.80	43.08	45.57	46.19	52.58
Production and mineral tax expense					
Natural Gas ($/*Mcf*)	0.06	0.07	0.06	0.04	0.06
Crude Oil *($bbl)*	0.66	0.67	0.70	0.46	0.84
NGL *($bbl)*	-	-	-	-	-
Total ($/*BOE)*	0.48	0.50	0.51	0.33	0.57
Cash administrative expenses(3)					
Natural Gas ($/*Mcf*)	0.95	1.11	0.52	0.52	1.70
Crude Oil *($bbl)*	5.69	6.65	3.15	3.13	10.18
NGL *($bbl)*	-	-	-	-	-
Total ($/*BOE)*	5.15	5.90	2.88	2.82	9.16
Operating netback received(4)					
Natural Gas ($/*Mcf*)	0.38	0.67	(0.10)	0.94	(0.03)
Crude Oil *($bbl)*	67.99	58.78	71.45	69.57	72.14
NGL *($bbl)*	38.21	36.51	36.29	35.47	44.51
Total ($/*BOE)*	41.17	36.68	42.18	43.04	42.85

Notes:

(1) Represents net production.

(2) Excludes sulphur and other revenue.

(3) PrairieSky does not incur operating expenses. Cash administrative expenses, which are administrative expenses excluding non-cash share-based compensation, include expenses associated with land administration, accounting and auditing functions necessary to administer and collect royalty payments and are allocated to natural gas and oil based on each product's share of total product revenue. Cash administrative expenses include any cash settled share-based compensation in the period. Cash administrative expenses are then divided by the average production (or commodity) in the period to

generate a cash margin per unit sold. Cash administrative expenses are a non-GAAP measure as defined in the Company's management's discussion and analysis for the periods ended March 31, 2025 (under the section *"Non-GAAP Measures and Ratios*" starting at page 21), June 30, 2025 (under the section "*Non-GAAP Measures and Ratios*" starting at page 24), September 30, 2025 (under the section "*Non-GAAP Measures and Ratios*" starting at page 24) and December 31, 2025 (under the section "*Non-GAAP Measures and Ratios*" starting at page 27), each of which sections are incorporated by reference in this AIF. The Company's management's discussion and analysis for each of the periods noted above are available on SEDAR+ at www.sedarplus.ca under PrairieSky's company profile.

(4) Operating netbacks are calculated by subtracting royalties paid (production and mineral tax expense) and cash administrative expenses from royalty revenues. This amount is then divided by the average production (or commodity) in the period to generate a cash margin per unit sold. Operating netback is a non-GAAP measure which is defined in the Company's management's discussion and analysis as operating netback for the periods ended March 31, 2025 (under the section "*Financial Results – Operating Results*" starting at page 6 and under the section "*Non-GAAP Measures and Ratios*" starting at page 21), June 30, 2025 (under the section "*Financial Results – Operating Results*" starting at page 6 and under the section "*Non-GAAP Measures and Ratios*" starting at page 24), September 30, 2025 (under the section "*Financial Results – Operating Results*" starting at page 7 and under the section "*Non-GAAP Measures and Ratios*" starting at page 24), and December 31, 2025 (under the section "*Financial Results – Operating Results*" starting at page 7 and "*Non-GAAP Measures and Ratios*" starting at page 27), each of which sections are incorporated by reference in this AIF. The Company's management's discussion and analysis for each of the periods noted above are available on SEDAR+ at www.sedarplus.ca under PrairieSky's company profile.

DESCRIPTION OF PROPERTIES

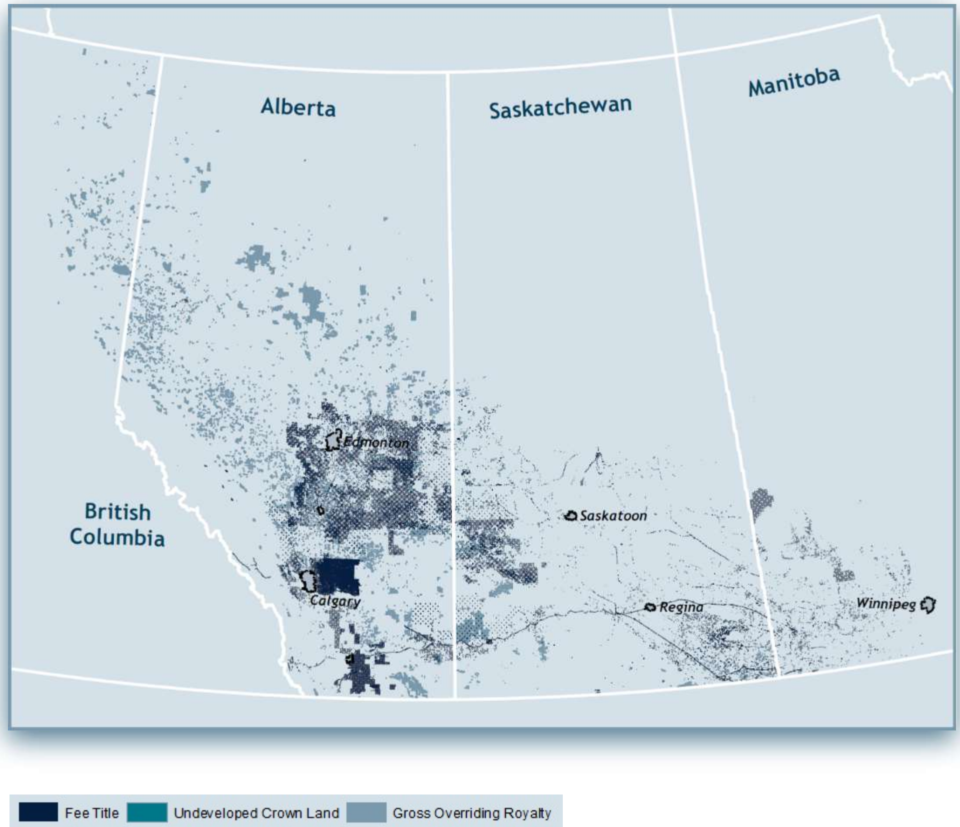
The assets of PrairieSky are comprised of: (i) the Fee Lands, encompassing approximately 9.9 million acres; (ii) the Lessor Interests; (iii) the GORR Interests, encompassing approximately 8.4 million acres of the GORR Lands; (iv) the GRT Interests, encompassing approximately 0.3 million acres of the GRT Lands; (v) approximately 9,500 acres of Crown Interest Lands; (vi) the Seismic Licence and other proprietary seismic data together encompassing approximately 54,600 kilometres of 2D seismic and approximately 20,200 square kilometres of 3D seismic with coverage of approximately 5.0 million acres; and (vii) certain other related assets.

The Fee Lands are located in the Western Canadian Sedimentary Basin, predominantly in the provinces of Alberta and Saskatchewan.

Approximately 16,000 leases are currently active on the Fee Lands and 372 lessees are engaged in exploring for and producing oil and natural gas on the Fee Lands.

Map of PrairieSky Fee Lands, GORR Interests and Other Interests

Below is a map of the Royalty Properties indicating those lands which are Fee Lands, GORR Interests (including GRT Interests) and Crown Interest Lands as at December 31, 2025.



Lands

The Company has one of the largest independently-owned portfolios of fee simple mineral title in Canada with approximately 11.3 million acres of Fee Lands, of which approximately 9.9 million acres are comprised of oil and/or natural gas rights. For the period ended December 31, 2025, royalty revenue from the Fee Lands accounted for approximately 62% of the total royalty revenue of PrairieSky. In addition, all bonus consideration and lease rentals are earned from Fee Lands.

The Fee Lands include a geologically diverse portfolio of properties that span the stratigraphic column from surface to basement. There is potential for the same section of land to be leased and re-leased on the basis of geological grouping, therefore allowing multiple lessees the right to drill and explore for, and ultimately produce from, different formations depending on the particulars of their leasing arrangement. Geological groups that form part of the Fee Lands include: (i) Surface to Top Colorado, focusing on shallow gas and Belly River oil development; (ii) the Colorado Group, which includes the Cardium Formation and the Viking Formation in both Alberta and Saskatchewan; (iii) the Mannville Group, which includes light oil (Detrital/Basal-Quartz/Ellerslie/Ostracod Formations), heavy oil (Cummings/Lloydminster/General Petroleum/Rex/Sparky and Waseca Formations) and natural gas (Glauconitic Formation and Upper Mannville Fahler/Wilrich/Notikewin Formations); (iv) the Jurassic to Base Mississippian, which includes the Rock Creek, Nordegg, Rundle Group, Banff, Midale and Bakken Formations; and (v) the Devonian, which includes the Nisku and the Duvernay Formations.

GORR Lands

The Company holds GORR Interests in approximately 8.4 million acres of GORR Lands. The substantial majority of the GORR Lands were acquired in connection with the Range Royalty Acquisition and the CNRL Royalty Acquisition, with additional GORR Lands acquired in targeted plays, including the Clearwater. Most recent drilling activities on the GORR Lands were predominantly focused on the Viking Formation in

Southwestern Saskatchewan and Alberta, the Mannville Stack which includes the Cummings, Lloydminster, General Petroleum, Rex, Sparky and Waseca Formations in the Cold Lake region, as well as on both the Lindbergh and Onion Lake thermal projects, the Clearwater sands in North Central Alberta, the Duvernay Formation at Willesden Green, the Montney/Doig, Cardium, Spirit River and Dunvegan in the Deep Basin and the Montney/Doig in Northeast British Columbia.

GRT Lands

The Company holds approximately 0.3 million acres of GRT Lands which represent minor fractional shares of lessor royalty interests reserved out of fee title lands throughout the Western Canadian Sedimentary Basin.

Crown Interest Lands

The Company holds approximately 9,500 acres of Crown Interest Lands, predominately in Alberta, which were acquired to complement the Company's checkerboard fee title position and to build land positions in strategic areas for purposes of royalty interest transactions.

CERTAIN OTHER MINES AND MINERAL RIGHTS

Coal rights, precious stone and other mines and mineral rights, including lithium and potash, in addition to oil and natural gas, are included in substantially all the Fee Lands. Due to the low commodity price outlook of coal, current estimates of mining and transportation costs in Alberta, or lack of commercial development at this time, the Company does not currently consider coal, precious stone or these other mineral rights material to its business.

Borrowings

As at December 31, 2025, the Credit Facility consisted of a $575 million unsecured extendible revolving credit facility and an unsecured $25 million extendible operating credit facility with a syndicate of Canadian banks. Borrowings under the Credit Facility bear interest at a Canadian bank prime rate, U.S. base rate, the CORRA or the SOFR, plus applicable margin on a variable grid based on certain financial ratios, over the prevailing applicable rate for the type of loan. The Credit Facility matures on February 28, 2028.

The Credit Facility has three financial covenants, whereby the Company’s ratio of adjusted consolidated senior debt to EBITDA for the trailing 12 months will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA for the trailing 12 months will not exceed 4.0:1.0, and the adjusted consolidated total debt to capitalization ratio will not exceed 55%. EBITDA used in the covenant calculation is net earnings adjusted for non-cash items, interest expense and income taxes. All covenants are calculated as at, and for the 12 months ended December 31, 2025. As at December 31, 2025, the Company was compliant with all covenants provided for in the lending agreement and forecasts compliance with such covenants until maturity.

As at December 31, 2025, the Company had $242.7 million drawn on its Credit Facility.

Industry Conditions

Companies carrying on business in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and, with respect to the pricing and taxation of oil and natural gas, through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian oil and natural gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation may be enacted, or whether existing legislation will be amended or repealed, including as a result of any shifts or changes in governmental policy due to new or existing administrations in the jurisdictions in which the Company conducts business. While such laws and regulations do not affect the Company in any 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 legislation, regulations and agreements carefully. The industry conditions set out below are not an exhaustive summary of all conditions, policies, projects, legislation, regulations and other matters which may have an impact on the Company's business and financial condition, the business of third parties with whom the Company conducts business and the oil and natural gas industry generally.

The unique nature of the Royalty Properties is expected to allow the Company to benefit from the upside potential of such properties at a reduced risk relative to traditional exploration and production companies. This advantage is a result of collecting royalty payments in respect of the Royalty Properties rather than directly conducting operations to explore for, develop and/or produce oil or natural gas, which is subject to greater regulatory scrutiny. However, legislation and regulations, including those outlined below, may impact the royalties received by the Company as an indirect participant in the development of oil and natural gas on its Royalty Properties. In addition, if the strategy of the Company were to change in the future such that it becomes a direct participant in the development or operation of its properties, whether as a working interest owner or an operator in respect of the Fee Lands that are currently undeveloped, or otherwise, the aforementioned industry regulation would become the burden of the Company in respect of such development.

PRICING AND MARKETING IN CANADA

Crude Oil

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

Since June 2023, OPEC+ producers have had to target lower oil supply and implement voluntary production cuts in order to stabilize the price of oil. The voluntary production cuts were extended in December 2024, with a plan to gradually phase out these adjustments by the latter half of 2026; however, OPEC+ announced a strategic pause on production increases for Q1 2026 in response to typical seasonal weakness in first quarter oil demand and concerns about potential supply surpluses. The OPEC+ producers continue to meet monthly to approve gradual adjustments in light of current global market conditions and economic outlook.

While the trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints, tariffs, surtaxes and other trade restrictive measures or countermeasures, sanctions and enforcement actions affecting oil producing countries, and the conflicts and/or political environments in Ukraine, Venezuela and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Exposure to Widespread Pandemic and Risks Related Thereto*", "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Natural Gas

Negotiation 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 of sale. 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 NGL, including ethane, butane, propane and pentane 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 NGL, 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

The Canadian Energy Regulator (the *CER*) is responsible for governing the export of crude oil, natural gas and NGL from Canada. The CER's governing legislation is the *Canadian Energy Regulator Act* (the *CERA*) and the *Impact Assessment Act* (the *IAA*).

Exports of crude oil, natural gas and NGL 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*). The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas not exceeding 30,000 m3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL).

Exporters are free to negotiate prices and other terms with purchasers, provided that they meet the reporting obligations set out in the Part VI Regulation and that export contracts continue to meet certain criteria prescribed by the CER and the Canadian 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 NGL is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Growing production and a lack of new and expanded pipeline and rail infrastructure capacity have caused producers in Western Canada to experience low commodity pricing relative to other markets in the last several years. However, the operationalization of LNG Canada's Kitimat facility in June 2025 has increased export capacity for natural gas from Western Canada and the commercial operation of the Trans Mountain Pipeline expansion has increased capacity for the transportation of crude oil to tidewater on the west coast of British Columbia. See "*Risk Factors - Gathering and Processing Facilities, Pipeline Systems and Rail*".

PIPELINES

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. 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 and the prices received by producers.

Under the *Constitution Act*, 1867, interprovincial and international pipelines fall within the federal government's jurisdiction. Under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty. Consequently, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition. These issues often relate to Indigenous rights and title, the government's duty to consult and accommodate Indigenous Peoples and the sufficiency of all relevant environmental review processes and assessments. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals at several levels of government in the United States. Further, with the change of the United States administration in 2025, there is additional uncertainty regarding the actions the Trump administration may take with respect to export pipelines.

In the face of such regulatory uncertainty, the Canadian oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, 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.

The federal government has introduced the *Building Canada Act* and Major Projects Office (the *MPO*) to assist with fast-tracking projects of national interest through regulatory barriers. In a memorandum of understanding signed by the federal government and Province of Alberta on November 27, 2025 (the *Canada-Alberta MOU*), the federal government committed to supporting a new pipeline that will deliver low-emission bitumen to the northern British Columbia coast for shipping to Asian markets, if certain conditions are met by the Alberta government. The Alberta government has agreed to prepare an application for the pipeline project and submit it to the MPO before July 1, 2026.

Specific Pipeline Updates

Line 5 Tunnel Replacement Project

In December 2023, regulators in the State of Michigan approved Enbridge's Line 5 Tunnel Replacement Project (*Line 5*), marking the end of a more than three-year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. While state approval has been granted, Line 5 still requires federal permitting from the U.S. Army Corps of Engineers, which has published a draft environmental impact statement and initiated the federal review process. The U.S. Army Corps of Engineers had previously indicated that a final federal permitting decision was expected in the fall of 2025; however, that decision has since been delayed into 2026.

Enbridge has also proposed a 41-mile reroute for Line 5 around the Bad River Band of Lake Superior Chippewa's reservation (the *Reroute*). In November 2024, the Wisconsin Department of Natural Resources issued construction permits for the Reroute, a condition of which is that the Reroute must be completed by November 14, 2027.

The Prince Rupert Gas Transmission Line

In March 2024, a jointly owned subsidiary of the Nisga'a Nation and Western LNG acquired the Prince Rupert Gas Transmission Line (the *PRGT Project*), a ready-to-construct pipeline that is intended to supply the proposed Ksi Lisims LNG Project.

The PRGT Project received an Environmental Assessment Certificate (the *BC EAC*) from the British Columbia Environmental Assessment Office (the *BC EAO*) on November 25, 2014. On April 25, 2019, the PRGT Project was granted a one-time, five-year extension. This extension moved the deadline for the start of construction to November 25, 2024, as required by the BC EAC. On June 5, 2025, the BC EAO determined that the project had been substantially started on November 25, 2024, as mandated by the BC EAC (the *June Decision*). Later in 2025, the BC EAO approved two amendment applications related to route and termination point changes.

In September 2025, a coalition of community groups and Luutkudziiwus, a Gitxsan Hereditary Chief, each commenced legal proceedings against the BC EAO seeking to quash the June Decision. Luutkudziiwus also alleged the Crown breached its duty to consult and accommodate in respect of impacts of the June Decision. These proceedings are ongoing and could lead to delays and further conditions being imposed on the PRGT Project.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have been constrained in recent years due to increasing North American supply, limited access to markets, and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access broader 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 in Western Canada have led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations.

In January 2025, the U.S. Department of Energy resumed processing LNG export applications to countries without a free trade agreement, ending the temporary pause implemented by the previous administration. Export permits have been approved for new LNG projects in U.S. jurisdictions such as Jefferson County, Texas and Cameron Parish, Louisiana. In March 2025, President Trump announced plans to develop a $44 billion LNG project in Alaska for export to Asian markets. This was followed by Baker Hughes' announcement in November 2025 of its definitive agreement to provide key equipment for the project. It is uncertain at this time the effect this may have on Canadian LNG export projects, including demand for the export of LNG.

Development of both provincial and federal net zero frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

Proposed LNG Export Terminal Updates

Woodfibre LNG Project

In December 2019, the CER approved a 40-year export licence for the Woodfibre LNG project (the *Woodfibre LNG Project*), a net zero LNG export facility being developed through a joint venture between Pacific Energy Corporation (Canada) Limited and Enbridge Inc. By the end of September 2025, the Woodfibre LNG Project was more than 50% complete and is expected to be substantially completed in the third quarter of 2027.

Cedar LNG Project

Cedar LNG Export Development Ltd.'s (*Cedar LNG*) Cedar LNG project (the *Cedar LNG Project*) near Kitimat, British Columbia is set to be the first Indigenous majority owned LNG project in the world. The BC EAO completed its assessment of the application for an environmental assessment certificate in November 2022 on its own behalf and on behalf of the Impact Assessment Agency of Canada (the *IAAC*). On March 15, 2023, both the provincial and federal government provided a decision statement indicating the Cedar LNG Project may proceed.

On June 25, 2024, a positive final investment decision was declared for the Cedar LNG Project and construction commenced in early July 2024. Cedar LNG has announced that it anticipates peak construction in 2026 and an in-service date in late 2028.

The Cedar LNG Project is awaiting the BC EAO and IAAC's decision on an amendment application to increase the liquefaction capacity from 400 to 500 million standard cubic feet per day of natural gas and to house workers aboard the floating Cedar LNG facility.

Ksi Lisims LNG Project

The Nisga'a Nation, Rockies LNG Limited Partnership and Western LNG are proposing to jointly build the Ksi Lisims LNG natural gas liquefaction and marine terminal project (the *Ksi Lisims LNG Project*) to be located on a site owned by the Nisga'a Nation in British Columbia. The Ksi Lisims LNG Project received federal and provincial environmental assessment approvals on September 15, 2025. Construction has not yet begun but it is anticipated the Ksi Lisims LNG Project could be operational as early as 2029.

In August 2025, the British Columbia Supreme Court dismissed legal proceedings initiated by the Gitanyow Huwlip Hereditary Chiefs in October 2024.

In October 2025, the Lax Kw'alaams Band and the Metlakatla First Nation filed separate judicial review applications in Federal Court, each citing concerns about the adverse impacts of the Ksi Lisims LNG Project. Both nations have outstanding Aboriginal title claims for the Mylor Peninsula before the British Columbia Supreme Court. These proceedings are ongoing and could lead to delays and further conditions being imposed on the Ksi Lisims LNG Project.

Major Projects Office

In August 2025, Prime Minister Carney launched the new MPO, created under the *Building Canada Act*, which is intended to streamline the regulatory approval process as well as coordinate financing of designated nation-building projects. Since its launch, Prime Minister Carney has announced two tranches of projects that have been referred to the MPO for further review and consideration, which include, among others, the LNG Canada Phase 2 project in Kitimat, British Columbia, and the Ksi Lisims LNG Project.

LAND TENURE

Mineral Rights

Except for Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (for the purposes of this section, collectively, ″leases″) for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. Provincial governments in Western Canada conduct land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

Rights to explore for and produce oil and natural gas from privately owned freehold mineral lands are granted by a lease or other contractual agreement on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

The GORR Interests are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

Surface Rights

To develop oil and natural gas resources, it is necessary for the working interest owner or operator to have access to the surface lands as well. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the surface landowner. Where an agreement cannot be reached, each province has developed its own process for obtaining surface access to conduct operations that working interest owners or operators must follow throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

ROYALTIES AND INCENTIVES

Each province has legislation and regulations that govern royalties, production rates and other matters relevant to the industry. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral 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 production.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, 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, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the oil and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Producers and working interest owners of oil and/or natural gas mineral rights may also create 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, the terms of which are subject to negotiation.

The Company has the flexibility to negotiate and adapt its royalty arrangements with third parties to affect the profitability of the exploration, development and production of oil and natural gas related to its Lessor Interests or GORR Interests in the appropriate circumstances, including consideration of the existing royalty regime established by each province (as described below) and any amendments to that regime. In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), either freehold mineral taxes or production taxes are levied annually on the production of oil and natural gas from freehold lands, or a mineral rights acreage tax is charged on mineral ownership, in each of the Western Canadian provinces where the Crown does not hold the mineral rights. Freehold mineral tax, production tax and acreage tax vary by jurisdiction.

General

The Canadian 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 oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to water use and conservation, 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. In addition, future changes to legislation and the underlying regulatory requirements, including legislation related to air pollution and GHG emissions, may impose further requirements on operators and other energy industry participants.

Shifts in government policy by the introduction of new, or amendments to existing requirements or restrictions can impact the Company's operations. Restrictions on fossil fuel-based energy use, emission limits, and new environmental obligations and requirements could have a material adverse impact on the Company's business, financial condition, results of operations and prospects.

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.

Impact Assessment Act

The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure, and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CER reviews applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IAAC or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAAC.

Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the CER and/or IAAC Agency will have to issue their report(s) 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.

Clean Fuel Regulations

On June 21, 2022, the *Clean Fuel Regulations* (the *CF Regulations*) came into force, enacted under the *Canadian Environmental Protection Act* (*CEPA*), with the objective of achieving 30 million tonnes of annual reductions in GHG emissions by 2030. The CF Regulations require liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity (*CI*) of the liquid fossil fuels they produce in, and import into, Canada. The CF Regulations have also established a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation. In the Canadian federal budget released on November 4, 2025 (*Budget 2025*), the federal government announced that it plans to introduce amendments to the CF Regulations to help reduce reliance on imported fuels, strengthen domestic supply chains and support jobs in agriculture, forestry and waste sectors. See "*Industry Conditions – Climate Change Regulation – Federal Policies*".

Output-Based Pricing System Regulations

The Output-Based Pricing System Regulations enacted under the *Greenhouse Gas Pollution Pricing Act* (Canada) (the *GGPPA*) were amended on November 22, 2023. These amendments involved adding and revising output-based standards, enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated Output-Based Pricing System (the *OBPS*) introduced a 2% fixed annual tightening rate for most output-based standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage experienced a 1% adjusted tightening rate from 2023 onwards. In March 2025, the federal government made further amendments to the OBPS, aligning the system with the elimination of the federal fuel charge effective April 1, 2025. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal – Regulatory Framework for the Oil and Gas Sector Greenhouse Gas Emissions Cap*".

Regulatory Framework for the Oil and Gas Sector Greenhouse Gas Emissions Cap

On November 4, 2024, the federal government released the proposed *Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations* (the *Proposed Emissions Cap Regulations*). The Proposed Emissions Cap Regulations would establish a cap-and-trade system that would apply to a wide range of industrial activities within the oil and gas sector, including onshore and offshore oil and gas production, oil sands production and upgrading, natural gas production and processing and LNG production. Under the cap-and-trade system, the federal government would determine a maximum threshold for annual emissions and freely issue emissions allowances in an amount equal to the cap. The initial cap would be based on 2026 emissions (attributed according to a formula set out in the Proposed Emissions Cap Regulations). The cap for the first compliance period, from 2030 to 2032, would be 27% below 2026 attributed emission levels for affected facilities. This reduction is anticipated to correspond to a 35% decrease from 2019 emission levels. This cap-and-trade system has been criticized by provinces and industry on the basis that it amounts to a production cap. The cap-and-trade system, if implemented, could have a material adverse impact on the Company's business, financial condition, results of operations and prospects.

To date, the Proposed Emissions Cap Regulations have not been implemented. The federal government under Prime Minister Mark Carney has shifted the country's climate priority towards economic competitiveness. Additionally, per the Canada-Alberta MOU, the federal government has committed to not implementing the Proposed Emissions Cap Regulations in consideration of the other commitments made in the Canada-Alberta MOU.

Oil Tanker Moratorium Act

The *Oil Tanker Moratorium Act* (Canada), enacted in 2019, imposed a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban has been criticized as preventing pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. In response to discussions about potential limited exemptions related to future oil pipelines in Northern British Columbia, the British Columbia government signed the North Coast Protected Declaration on November 5, 2025 that urges the federal government to uphold and defend the *Oil Tanker Moratorium Act*, and to reject any exemptions. However, in the Canada-Alberta MOU, the federal government indicated an openness to making adjustments to the *Oil Tanker Moratorium Act* to assist in the construction of a new Alberta pipeline that will export bitumen to Asian markets.

Alberta

The Alberta Energy Regulator (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* (Alberta) (the *OGCA*), the *Oil Sands Conservation Act* (Alberta), the *Pipeline Act* (Alberta), the *Water Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta) (the *EPEA*). 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 AER's responsibilities exclude the functions of the Alberta Utilities Commission (the *AUC*) and the Land and Property Rights Tribunal, 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 (the *AEPA*) (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, guided by the Land-use Framework, 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.

Seismic Monitoring

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 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.

In December 2025, the AER updated *Directive 065: Resources Applications for Oil and Gas Reservoirs* to include provisions for managing disposal-induced seismic activity that require disposal well operators to conduct seismic hazard assessments. The AER has also developed monitoring and reporting requirements that apply to all 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. 2A, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the *Seismic Protocol Regions*). 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 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.

Drought Response

On August 14, 2024, Alberta released its Alberta Drought Response Plan (the *Drought Response Plan*), which was updated on April 1, 2025. The intent of the Drought Response Plan is to ensure Alberta is prepared for the potential of widespread drought. The Drought Response Plan describes preparation, planning and response activities that AEPA will implement to effectively address the full range of possible drought conditions, which may range from localized impacts to multiple river basins simultaneously.

The Drought Response Plan encompasses a range of regulatory tools to address drought conditions across all stages, comprising the approval of water shortage response plans, issuance of temporary diversion licenses, facilitation of temporary water licence transfers, arrangements for water assignment, and modifications to existing licenses and approvals under the *Water Act*. Other available mechanisms include water management orders that can be enacted under the *Water Act*, alongside environmental and emergency environmental protection orders under the EPEA.

Should a water emergency be declared, the Drought Response Plan permits the issuance of water management orders that could result in the suspension of certain authorizations under the *Water Act*, halting water diversion, and strictly regulating the use and allocation of water. These orders may also direct necessary actions to counteract or mitigate detrimental effects on aquatic ecosystems or human health.

The Drought Response Plan could reduce the availability of water for extraction processes on the Royalty Properties, which could have a material adverse impact on the Company's business, financial condition, results of operations and prospects.

British Columbia

In British Columbia, the *Energy Resource Activities Act* (the *ERAA*) (formerly the *Oil and Gas Activities Act*) regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the ERAA, the BC Energy Regulator (the *BCER*) has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities, and recent amendments to the ERAA now provide the BCER with discretion to impose environmental and remediation obligations on persons with a legal or beneficial interest in production or profits from energy resource activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources and requires the BCER to consider these environmental objectives in deciding whether or not to authorize a particular activity. The *Renewable Energy Projects (Streamlined Permitting) Act* came into effect on July 1, 2025 and expanded the BCER's mandate to include the oversight of certain renewable energy projects and associated transmission lines.

In addition, the *Petroleum and Natural Gas Act*, in conjunction with the ERAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work and well test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and permits, licences, and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Water Sustainability

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams which companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the Dam Safety Regulation. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the BCER has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent, the relevant industry regulators will respond to this issue.

Seismic Monitoring

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation* requires a producer to suspend its operations if they trigger a seismic event with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BCER before resuming production. All natural gas producers are required to conduct ground monitoring and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

The BCER has designated two areas as seismic monitoring and mitigation areas: the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek, and the North Montney Seismic Monitoring and Mitigation Area (together, the *Seismic Areas*). Special project orders were issued that require permit holders in the Seismic Areas to comply with additional requirements before they can conduct hydraulic fracturing operations. Additional requirements include developing a seismic monitoring and mitigation plan that is approved by the BCER and notifying the BCER and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BCER on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds based on earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the seismic event and developing an approved protocol for subsequent events, to initiating such protocols, to suspending operations until permitted to resume by the BCER. Future seismic events outside of the Seismic Areas may trigger the introduction of similar requirements elsewhere in the province.

Environmental Assessment and Energy Action Framework

British Columbia's environmental assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, underscores early engagement and aims to improve Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act* in 2019, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" contained in the *Reviewable Projects Regulation* captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the BC EAO will consider the environmental, health, cultural, social and economic effects of a proposed project. The BC EAO is conducting a substantial review in consultation with First Nations of the *Environmental Assessment Act* to evaluate whether it is meeting its purpose. The review is expected to continue until the end of 2027, with certain near term priorities expected to be addressed by Spring 2026.

On March 14, 2023, the Province of British Columbia announced a new energy action framework (the *Action Framework*). The Action Framework intends to mandate proposed LNG facilities in or entering the environmental assessment process to pass an emissions test and develop a credible net-zero plan by 2030. It also intends to implement a regulatory emissions cap for the oil and natural gas industry to meet British Columbia's 2030 emissions reduction target. Further, it establishes a clean-energy and major projects office to expedite investments in clean energy and technology for sustainable job creation. The Action Framework is also intended to create a BC Hydro task force aimed at hastening the electrification of British Columbia's economy through renewable electricity for homes, businesses, and industries. While British Columbia has continued to advance policy development and consultation related to the Action Framework, including potential regulatory measures applicable to the oil and gas sector, no binding emissions cap legislation or regulations have been implemented as of the date of this AIF. See "*Industry Conditions – Climate Change Regulation – British Columbia*".

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of 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* and *The Petroleum Registry and Electronic Documents 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 a 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.

Saskatchewan launched the Inactive Liability Reduction Program (the *ILRP*) in January of 2023. The ILRP aims to reduce the total number of inactive liabilities for oil and gas companies. In 2023, the program required oil and gas companies to retire 5% of their inactive liabilities such as inactive wells, and facilities in Saskatchewan. This percentage was maintained at 6% for 2025 and will increase to 7% for 2026.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Business, Mining, Trade and Job Creation develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of oil and natural gas resources. Oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the *MBOGA*), *The Oil and Gas Production Tax Act* and related regulations and guidelines. *The Environment Act* establishes the environmental assessment and licensing process for developments in Manitoba for projects which may have the potential to cause significant environmental and/or human health effects. Projects which are defined as developments which must undergo the environmental assessment and licensing process are listed in the *Classes of Development Regulation*.

Liability Management Programs

Alberta

The AER oversees liability management in the Province of Alberta. Following replacement of Alberta’s Liability Management Program, the AER continues to implement its Liability Management Framework (the *AB LMF*). The primary goals of the AB LMF are to assist in addressing the Orphan Well Association’s (the *OWA*) inventory and creating a regulatory framework that will better manage site reclamation throughout the lifecycle of a project. The Province of Alberta has an orphan fund (the *Orphan Fund*) to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded through a levy, however the provincial government has advanced loans to the Orphan Fund and covered levy payments owed by licensees.

As a result of the Supreme Court of Canada's (the *SCC*) decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the *Redwater Decision*), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets 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. The burden of a defunct licensee’s abandonment and reclamation obligations first falls on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure.

British Columbia

The purpose of the BCER's Comprehensive Liability Management Plan (the *CLMP*) is to ensure that 100% of the costs associated with the reclamation of oil and natural gas sites is paid by industry, rather than the Government of British Columbia or residents of British Columbia. In April 2022, the Permittee Capability Assessment Program (the *PCA*) was implemented to replace the Liability Management Rating Program (the *BC LMR Program*). Similar to the AB LMF, the PCA program is intended to be a holistic evaluation of permittees throughout the development life cycle and is intended to replace the BC LMR Program. The PCA program is intended to mitigate risk and minimize pressure on the Orphan Site Reclamation Fund (the *OSRF*).

A liability-based levy paid to the OSRF replaced the previously existing orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The ERAA permits the BCER to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the *Dormancy Regulation*) established the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that became dormant between 2019 and 2023 or become dormant after 2024.

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 licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the *Oil and Gas Orphan Fund*) established under the SKOGCA. The Oil and Gas Orphan Fund 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 or financially able party to deal with the abandonment and/or reclamation responsibilities. The Oil and Gas Orphan Fund is funded by licensees through a levy and, where applicable, through security deposits required under the SK LLR Program.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating or capability assessment program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA also establishes the Abandonment Fund Reserve Account (the *Abandonment Fund*). The Abandonment Fund is a source of funds that may be used to operate or abandon a well or facility when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred, as well as annual levies for inactive wells and batteries.

CLIMATE CHANGE REGULATION

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and 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 adverse impact on the Company's business, financial condition, results of operations and prospects.

International Treaties and Commitments

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the *UNFCCC*) since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. Canada is a signatory to the Paris Agreement, pursuant to which participating countries have committed to preventing global average temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to no more than 1.5° Celsius. Canada has made a number of international climate commitments in connection with UNFCCC processes, including pledges to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) phase out unabated thermal coal exports by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) end new direct public financing for international unabated fossil fuel investments and projects; and (v) achieve 100% zero-emission vehicle sales for new light-duty vehicles by 2035. During the 2024 United Nations Climate Change Conference, nearly 200 countries adopted the New Collective Quantified Goal on climate finance and reached an agreement that will triple financing to developing countries for these initiatives. Canada also committed to international action to reduce methane and industrial GHG emissions. At the 2025 UN Climate Change Conference (*COP30*) held in Brazil, Canada advanced carbon market initiatives and adaptation finance, but faced scrutiny for LNG expansion and uncertainty around its approach to oil and gas emissions caps.

Federal Policies

The federal government previously pledged to cut its emissions by 30% from 2005 levels by 2030. In connection with this target, the federal government released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016 and in March 2022, the federal government 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. In 2025, the federal government published the 2025 Progress Report on the 2030 Emissions Reduction Plan, outlining the cumulative implementation status of measures and reporting on developments since the first report that was published in the 2023 Progress Report.

The federal government formally announced Canada's new Climate Competitiveness Strategy in November 2025, which aims to attract greater investment and build a strong net-zero economy. The strategy emphasizes a strengthened industrial carbon pricing system underpinned by long-term prices and improved benchmarking. The strategy also promises to provide clarity on greenhouse gas regulations to complement the amended carbon pricing system. The federal government also proposed extending the full credit rates for CCUS, expanding the list of critical minerals eligible for the clean technology manufacturing investment tax credit, and introducing a new clean electricity investment tax credit. These initiatives could impact the regulatory environment of the oil and natural gas industry.

On February 5, 2026, the federal government introduced stronger greenhouse gas emission standards that put Canada on a path to achieve a goal of 75% electric vehicle sales by 2035 and 90% electronic vehicle sales by 2040. In addition, the federal government launched a five-year electric vehicle affordability program to lower the cost of electric vehicles for Canadians and create a stronger domestic consumer market.

Canadian Net-Zero Emissions Accountability Act

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.

Greenhouse Gas Pollution Pricing Act

Canada's GHG regime is enacted pursuant to the GGPPA, which has two parts: the OBPS and a regulatory fuel charge (the *Fuel Charge*) imposing an initial price of $20/tonne of carbon dioxide equivalent (CO_2e). 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. 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.

The constitutionality of the GGPPA was challenged by several jurisdictions, with the SCC ultimately upholding its constitutionality. 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 Benchmark. Effective April 1, 2025, the federal government set the fuel charge rate to zero, effectively removing consumer-facing carbon price requirements for provinces and territories. Provincial plans apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia, Newfoundland and Labrador, British Columbia, Québec, and the Northwest Territories while the OBPS applies in each of Yukon, Nunavut, Manitoba, and Prince Edward Island. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction* (*TIER*) *Regulation*), British Columbia 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. Increases under the OBPS are currently paused pending a review by the federal government, and for now, Alberta, British Columbia and Saskatchewan are deemed to continue to be compliant with federal equivalency standards. Proposed amendments to the TIER regulation in Alberta introduce some uncertainty to the province's equivalency status in 2026; however, under the Canada-Alberta MOU, the federal and Alberta governments agreed to finalize an agreement on industrial carbon pricing on or before April 1, 2026.

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds

On October 29, 2020, the federal government launched the $750 million Emission Reduction Fund to reduce methane and GHG emissions. The fund provides repayable funding to eligible onshore and offshore oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies. Part of this fund is directed towards methane reduction. The *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the *Federal Methane Regulations*) aim to reduce methane emissions from the oil and natural gas industry by implementing control measures to minimize unintentional leaks and intentional venting of methane.

On December 4, 2023, the Minister of Environment and Climate Change announced proposed amendments to the Federal Methane Regulations to further reduce emissions. These amendments align with international efforts, such as the International Energy Agency's call to curtail methane emissions from the oil and gas sector by 75% by 2030.

On March 11, 2024, the Minister of Energy and Natural Resources launched Canada's Methane Centre of Excellence and a request for proposals for methane mitigation and measurement projects. The federal government confirmed in Budget 2025 that it will finalize amendments to the Federal Methane Regulation.

Orders were issued in 2025 exempting British Columbia and Alberta from federal methane regulations as a result of equivalency agreements under CEPA. Saskatchewan remains exempt under a similar agreement finalized at the end of 2024.

Clean Fuel Regulations

The CF Regulations came into force on June 21, 2022, implementing the Clean Fuel Standard. The CF Regulations take a performance-based approach to reducing GHG emissions and 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 started at 3.5 gCO_2e/MJ, increasing by 1.5 gCO_2e/MJ each year until reaching 14 gCO_2e/MJ in 2030. The standard applies 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 CF Regulations offer compliance credits, tracked via the Credit and Tracking System, and create a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs. In Budget 2025, the federal government announced that it will introduce amendments to the CF Regulations to help reduce reliance on imported fuels, strengthen domestic supply chains and support jobs in agriculture, forestry and waste sectors.

Clean Electricity Regulation

The *Clean Electricity Regulations* were enacted on December 18, 2024 and include a target date to decarbonize electricity grids of 2050. Although enacted in December 2024, the emission restrictions under the *Clean Electricity Regulations* will not come into effect until January 1, 2035.

Under the *Clean Electricity Regulations*, electricity generating units that meet the applicability criteria will be subject to an annual emission limit based on each unit's generation capacity. A "unit" means an assembly consisting of equipment that is physically connected and operate together to generate electricity.

The *Clean Electricity Regulations* apply to a unit that meets the following criteria: (i) the unit uses any amount of fossil fuels to generate electricity, (ii) the unit has a generation capacity of at least 25 megawatts, and (iii) the unit is connected to an electricity system that is subject to the North American Electricity Reliability Corporation's standards. The *Clean Electricity Regulations* also permit the exclusion of emissions associated with the combustion of biomass and renewable natural gas, as well as emissions captured by carbon capture and storage projects and emissions generated during an emergency circumstance.

Under the Canada-Alberta MOU, the federal government suspended the application of the *Clean Electricity Regulations* in Alberta pending a new carbon pricing agreement, which will be administered through Alberta's TIER system. See "*Industry Conditions – Climate Change Regulation – Alberta*".

Air Pollutant Regulations

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

Framework to Phase Out Fossil Fuels

On July 24, 2023, the Minister of Environment and Climate Change released the *Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework* and the *Inefficient Fossil Fuel Subsidies Government of Canada Guidelines*. The federal government has used these documents to determine whether tax and non-tax measures constitute inefficient fossil fuel subsidies in light of the federal government's objectives related to Canada's G7 and G20 commitments to phase out inefficient fossil fuel subsidies. The federal government conducted a preliminary review of various subsidies but has yet to make any concrete decisions respecting the phasing out of such subsidies. Additionally, the enactment of the *Building Canada Act* in June 2025 adds uncertainty to whether proponents of oil and gas related projects deemed in the national interest will be required to meet these decarbonization criteria.

Bill C-59 – Anti-Greenwashing Legislation

In June 2024, Bill C-59, *the Fall Economic Statement Implementation Act, 2023* (*Bill C-59*), received royal assent. Bill C-59 introduced significant updates to the *Competition Act* with implications for environmental claims and collaborations. The amendments expand the *Competition Act*'s deceptive marketing provisions, requiring businesses making environmental claims about products or business practices to substantiate their statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. As of June 20, 2025, private parties could bring deceptive marketing claims before the Competition Tribunal, a right previously exclusive to the Competition Bureau. The introduction of Bill C-59 increased compliance risks for energy industry participants that make public environmental claims or engage in marketing respecting environmental responsibility.

In late 2025, Bill C-15, *An Act to implement certain provisions of the budget tabled in Parliament on November 4, 2025* (*Bill C-15*), was introduced in the House of Commons. Among other measures, Bill C-15 would implement proposals announced in Budget 2025 to amend the greenwashing provisions of the *Competition Act*. In particular, Bill C-15 would: (i) remove the requirement that environmental claims about a business or business activity be substantiated in accordance with internationally recognized methodology standards, while retaining a general requirement for adequate and proper substantiation; and (ii) remove the ability for private third parties to bring cases directly to the Competition Tribunal under the greenwashing provisions governing environmental claims made about the benefits of a business or business activity, while leaving intact private access rights under other misleading advertising provisions, including those applicable to product-level environmental claims.

Building Canada Act

The *Building Canada Act* was enacted on June 26, 2025 and is intended to streamline federal review and approval processes for identified "nation-building" projects by providing upfront regulatory certainty and a coordinated, single review process through the MPO. Projects that are designated as being in the national interest, based on contribution to Canada's resilience, autonomy and security, economic benefits, contribution to Indigenous interests, clean growth and Canada's climate objectives and the likelihood of successful project execution, may receive consolidated approvals and conditions, subject to public notice and consultation requirements. The federal government has referred several projects to the MPO, including LNG facilities, critical mining projects, and transmission projects.

Several environmental organizations and Indigenous groups have initiated challenges to the *Building Canada Act* on the basis of its broad powers to override environmental laws, limit public participation, and undermine constitutionally protected rights. Additionally, Indigenous groups have raised concerns that the projects will be designated without meaningful consultation and true consideration of Indigenous rights.

Alberta

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 TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. Starting in 2020, most TIER-regulated facilities were required to reduce emission intensity by 10%, with an additional 1% annual reduction thereafter. Subsequent amendments introduced a 2% annual reduction rate for facility-specific and high-performance benchmarks, replacing the previous facility-specific benchmarks for some facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, while facilities with significant prior reductions can use a high-performance benchmark to account for compliance costs. Facilities emitting 2,000 to 10,000 tonnes of CO_2e annually can now opt into the program under amended thresholds. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and may meet thresholds by either purchasing credits from other facilities, purchasing carbon offsets, or paying a levy to the Government of Alberta.

In February 2023, the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for CCUS projects. On April 1, 2025, the provincial government announced it would freeze the TIER industrial carbon price at $95/tonne indefinitely, which deviates from the federal schedule. However, Premier Danielle Smith has committed to increasing the TIER industrial carbon price to align with federal standards at $130/tonne in the Canada-Alberta MOU.

On September 16, 2025, the Alberta government announced two proposed amendments to the TIER regulation. The proposed amendments include (1) the recognition of on-site emissions reduction investments and (2) allowing smaller facilities to opt out if they previously opted into the TIER system.

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 TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026 and the federal equivalency is scheduled to be re-assessed in early 2026. In the Canada-Alberta MOU, the federal government recognized Alberta's jurisdiction over its TIER regulations, agreeing to work with the province to develop a globally competitive carbon pricing system. In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45%, ahead of schedule.

On September 26, 2025, the Minister of the Environment and the Government of Alberta entered into a written agreement recognizing the equivalency between the Federal Methane Regulations and Alberta's *Methane Emission Reduction Regulation* under the EPEA. This equivalency agreement has a term of five years, applying until 2030 and on October 23, 2025, the federal government made an order declaring the Federal Methane Regulations do not apply in Alberta.

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 the Quest and Alberta Carbon Trunk Line projects. In 2024, the Government of Alberta announced the Alberta Carbon Capture Incentive Program (the *ACCIP*) which offers a 12% grant on new eligible CCUS capital costs and is designed to complement the federal incentives. The ACCIP is intended to support Alberta's strategy to stay at the forefront of CCUS development and environmental sustainability. In the Canada-Alberta MOU, the Alberta government has committed to extending the ACCIP to support the new Pathways Plus CCUS project that will support the development of a new low-emissions bitumen pipeline.

British Columbia

Pursuant to British Columbia's Climate Leadership Plan, the Government of British Columbia has targeted to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

The *Greenhouse Gas Industrial Reporting and Control Act* (the *GGIRCA*) sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects. British Columbia was the first Canadian province to implement a revenue-neutral fuel charge.

Pursuant to British Columbia's clean energy plan (the *CleanBC Plan*), the Government of British Columbia has agreed to reduce GHG emissions by 40% by 2030. The CleanBC Plan targets British Columbia's industrial, transportation, construction, and waste sectors with strategies such as: increasing clean energy generation, requiring 15% renewable content in natural gas by 2030, reducing diesel and gasoline carbon intensity by 20%, electrifying oil and gas production, cutting methane emissions by 45%, and incentivizing zero-emission vehicles. The CleanBC Plan outlines pathways, including for the oil and natural gas industry, to achieve emissions targets and build a cleaner economy. The CleanBC Plan was further revised with the "CleanBC Roadmap to 2030", pursuant to which the Government of British Columbia committed to better align with the federal government's minimum national stringency standards for carbon pricing.

As part of the Government of British Columbia's 2023 budget, it was announced that starting April 1, 2023, British Columbia's carbon tax would increase to $65/tonne of CO_2e and would increase by $15/tonne each year until it reaches $170/tonne in 2030. As of April 1, 2025, British Columbia's carbon tax increased to $95/tonne of CO_2e. In April 2024, British Columbia's carbon pricing system switched to a new made-in-BC output-based pricing system (the *BC OBPS*). The new BC OBPS replaced the province's CleanBC Industrial Incentive Program, which had been in use since 2019. The BC OBPS applies to large industrial emitters and prices emissions that exceed specific limits. The BC OBPS is intended to provide flexible options to meet compliance obligations while ensuring emissions reductions for industry continue. Participation under the BC OBPS is mandatory for certain industrial producers under the GGIRCA, that emit above 10,000 tonnes of CO_2e per year and excludes certain fuels that will still have reporting requirements under GGIRCA. Similar to the federal system and Alberta's TIER system, there will be a voluntary opt-in option for certain industrial operations in regulated sectors that emit less than 10,000 tonnes of CO_2e per year. In order to support the new BC OBPS, the CleanBC Industry Fund underwent certain transitions to align with the new BC OBPS and remains in effect under the new carbon pricing system.

In November 2020, the federal government and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia. The equivalency agreement was set to expire in 2025, but has been renewed and will now expire on December 31, 2029.

Saskatchewan

The *Management and Reduction of Greenhouse Gases Act* (the *MRGGA*) regulates GHG emissions in the province. The Government of Saskatchewan released *Prairie Resilience: A Made-in-Saskatchewan Climate Change 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, established 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 had 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 CO_2e under their permitted amount. The OBPS program in Saskatchewan includes credits for emitters utilizing CCUS technologies at their facilities.

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, requiring facility licensees exceeding 50,000 tonnes of CO_2e annually to submit emissions reduction plans. These regulations aimed to cut annual emissions by 40% to 45% by 2025, achieving reductions of 4.5 million tonnes of CO_2e emissions by 2025 and 38.2 million tonnes of CO_2e emissions by 2030.

On April 10, 2019, Saskatchewan produced its first annual report on climate resilience. The report measured the province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among the goals was the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030. The 2023 Climate Resilience Report indicated that roughly 34.7% of SaskPower's electrical generation came from renewable sources in 2022. The report also suggested that total GHG emissions in 2022 were already below the 2025 target initially set.

In October 2019, The *Oil and Gas Conservation Amendment Act* was proclaimed into force, which 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 July of 2024, the Government of Saskatchewan and the federal government entered into an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on December 31, 2029.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act* (the *Implementation Act*). The *Implementation Act* included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. Initially, the *Climate and Green Plan Act* introduced a charge of $25/tonne of CO_2e on GHG emissions, but this was subsequently withdrawn from the legislation and the federal GGPPA applied in Manitoba. However, in March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, reintroduced the $25/tonne charge.

Following Manitoba's challenge of the GGPPA in the Federal Court, it was determined that the federal government's Fuel Charge would backstop Manitoba's system because Manitoba's pricing regime is not stringent enough. However, the federal Fuel Charge was eliminated on April 1, 2025. The $25/tonne imposed by the *Climate and Green Plan Implementation Act, 2020* does not match increases in the Federal Benchmark and therefore is not a comparable system. The original *Climate and Green Plan Implementation Act* also required the Government of Manitoba to establish five-year emissions reduction targets. The Government of Manitoba set the reduction target for the five-year period (2023 to 2027) at 5.6 megatonnes of CO_2e emulative emissions reductions.

Unlike Alberta, British Columbia, and Saskatchewan, the Province of Manitoba has no equivalent methane reductions regulations and is subject to the Federal Methane Regulation regime.

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 communities), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Bill S-211, *An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff* (the *Modern Slavery Act*) received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the *Modern Slavery Act*, entities that meet certain criteria are required to file public reports annually on the steps they have taken to prevent and reduce the use of forced labour and child labour in their supply chains. This includes entities engaged in producing, selling, or distributing goods in Canada or elsewhere, importing into Canada goods produced outside Canada, or controlling an entity engaged in either of the preceding activities. The bill outlines the steps these entities must take to prevent and reduce the risk that operations, including those of third parties within the supply chain, make use of forced and/or child labour. See "*Risk Factors – Evolving Corporate Governance, Sustainability and Reporting Framework*".

INDIGENOUS RIGHTS

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous communities potentially 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, including the principle to seek free, prior and informed consent, which 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* (British Columbia) (*DRIPA*) became law in British Columbia. The Government of British Columbia released an 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 UNDRIP. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act (Canada) (the *UNDRIP Act*) came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the federal government 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.

The federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of the UNDRIP Act (the *Implementation Secretariat*), consulting with Indigenous Peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP principles. On June 21, 2023, the Implementation Secretariat released The United Nations Declaration on the Rights of Indigenous Peoples Act Action Plan (the *Action Plan*) with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe. In June 2024, the federal government tabled its Third Annual Progress Report on the implementation of the UNDRIP Act (the *Progress Report*), which provides various progress updates, including on the implementation of Canada's Action Plan. 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 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. On February 9, 2024, the SCC rendered its decision regarding the *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*, in which it made clear its opinion that UNDRIP has been incorporated into Canada's domestic law.

The federal government continues to encourage Indigenous equity ownership in energy and infrastructure projects, including LNG and pipelines. In 2024, the federal government implemented the Indigenous Loan Guarantee Program to provide greater access to capital for Indigenous groups seeking equity participation in energy, mining, transportation, and trade projects. The funding and scope was expanded in 2025. Under the *Building Canada Act* the federal government is empowered to designate projects as being in the national interest. There may be some risk for projects that are referred to the MPO in how the federal government will meet its duty to consult.

Recent and Relevant Case Law

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 January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nation Implementation Agreement (*Implementation Agreement*). The Implementation Agreement marks a significant shift in how the province and First Nations will jointly manage land, water, and resources. It focuses on cumulative effects within the BRFN's claim area by initiating land restoration efforts, establish protected zones to safeguard against development, and imposes restrictions on development activities. All of the goals will be carried out through a series of measures, including a $200 million restoration fund by June 2025, limits on new oil and natural gas development and a new planning regime for future oil and gas activities. At the outset, the BRFN received $87.5 million as a financial package over three years, with potential for greater benefits tied to oil and natural gas revenue sharing and provincial royalty revenues in the coming two financial years. In July 2024, BRFN filed a civil claim against the Province of British Columbia with respect to the first implementation plan made under the Implementation Agreement, which raises questions about implementation challenges of such an 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 British Columbia, Alberta and Canada at large. The Consensus Document implements various initiatives including: (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 Nation communities; and (vii) actions to promote education about Treaty 8 through collaborative promotion, anti-racism training and awareness building.

In July 2022, Duncan’s First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by BRFN. Duncan’s First Nation claims in its lawsuit that the Government of Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation’s treaty rights. Beaver Lake Cree Nation (*BLCN*) brought a similar treaty claim against the Government of Alberta in 2008, and after 10 years and millions of dollars spent attempting to advance the claim, BLCN filed an application for advanced cost which, if successful, would require both the Government of Alberta and federal governments to pay part of BLCN’s litigation costs. This claim ultimately made its way to the SCC, which ruled in favour of BLCN, establishing a new test regarding whether an applicant ″can afford″ litigation. The initial treaty claim has been remitted back to the trial court and the Government of Alberta has been ordered to contribute annually towards BCLN’s litigation costs until the trial is concluded or the litigation is resolved. The long-term impacts of these lawsuits on the Canadian oil and natural gas industry remain uncertain.

On February 19, 2025, the Federal Court of Canada (the *Federal Court*) held, in *Kebaowek First Nation v Canadian Nuclear Laboratories*, that the Canadian Nuclear Safety Commission’s failure to consider UNDRIP and its principle of free, prior, and informed consent when assessing the Crown’s duty to consult was an error of law. The Federal Court indicated that free, prior, and informed consent is not a veto, but a “right to a robust process” requiring deep and meaningful consultation with Indigenous Peoples. While there continues to be different interpretations of how to interpret UNDRIP, this case signals to oil and gas projects that UNDRIP provides an interpretive lens for assessing the requirement for consultation.

On February 28, 2025, the SCC held, in *Saskatchewan (Environment) v Metis Nation*, that the duty to consult operates between the assertion and final determination of Aboriginal title or rights. As such, if projects are on lands in which the Aboriginal title or rights claims remain unresolved, the duty to consult must still be fulfilled.

There have also been differing decisions in how Aboriginal title interacts with privately held lands, highlighting the unsettled nature of the law governing this relationship. On August 7, 2025, the British Columbia Supreme Court determined, in *Cowichan Tribes v Canada (Attorney General)*, that Aboriginal title and fee simple interests can co-exist, and proceeded to issue a declaration of Aboriginal title over an area that included private lands. This decision is currently under appeal.

On December 11, 2025, the New Brunswick Court of Appeal held, in *J.D. Irving, Limited et al. v Wolastoqey Nation*, that fee simple title and Aboriginal title cannot co-exist on the same parcel of land. As this area of law continues to develop, there may be implications for project development.

Risk Factors

The Company is subject to both risks that directly affect its business and operations, as well as indirect risks that impact third parties or industry generally. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set forth below should be read in conjunction with the "*Industry Conditions*" section above. These risks are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business, the business of third parties with whom the Company conducts business and the crude oil, NGL and natural gas business generally. Additional risks not presently known to PrairieSky or that PrairieSky currently deems immaterial could also materially affect the Company's business. If any of the following risks were to occur or materialize, the Company's business, financial condition, results of operations, prospects or reserves could be materially adversely affected.

Although the Company does not conduct operations on the Royalty Properties, but instead collects royalty payments in respect of the Royalty Properties resulting from the development of such properties, its business, financial condition, results of operations and prospects are linked to the risks that impact the oil and natural gas industry generally and in particular those which affect the lessees and/or operators that have or will have arrangements with the Company in respect of the Royalty Properties. Accordingly, where applicable, the information contained herein, including in particular the following risk factors, should be read in the context of both their direct and indirect (through such lessees and/or operators) impact on the Company's business, financial condition, results of operations and prospects.

Dependence on Lessees and/or Operators

The Company is dependent on lessees and/or operators of the Royalty Properties.

Third-party exploration and production companies are the lessees and/or operators of the Royalty Properties. The Company has limited to no ability to exercise influence over the operations on the Royalty Properties or the associated operating or capital costs, which could adversely affect the Company's financial performance, which adverse effect could prove to be material over time. The Company's revenues, which are derived from the Royalty Properties operated by third parties, depend upon a number of factors, most of which are outside of the Company's control. Such factors include: the extent of exploration on and development of the Royalty Properties; the timing and amount of capital expenditures on those properties; the operator's expertise, production practices and financial resources; the approval of other participants; the selection of technology and cost; risk management; compliance by third party lessees and/or operators with licence or lease terms relating to the Royalty Properties; and environmental compliance and remediation practices.

While the Company actively pursues additional leasing and royalty arrangements with lessees and/or operators for the Royalty Properties, there is no guarantee that the Company will be successful in securing additional leasing and royalty arrangements with lessees and/or operators with third parties. Further, for Royalty Properties or formations that are not held by production at the end of the primary term, there can be no assurance that the Company will be able to re-lease such properties or formations or, if it is able to re-lease such properties or formations, that the lease terms and rates will be as favourable to the Company.

The third-party exploration and production companies involved with the Royalty Properties may manage or participate in a wide variety of projects in the conduct of their business, which may result in such third parties diverting capital, development activity and expertise away from the Royalty Properties. In addition, third-party exploration and production companies involved in the Royalty Properties may defer or cancel capital projects in a low commodity price environment, have business interests or targets that are inconsistent with those of the Company, take action contrary to the Company's policies or objectives, be unable or unwilling to fulfill their obligations under their agreements with the Company, or experience financial, operational or other difficulties, including insolvency, which could limit the operators ability to continue operations and further develop such projects. The deferral or cancellation of development or capital projects conducted on the Royalty Properties may delay or reduce expected revenues from operations conducted by third parties on the Royalty Properties, which, in turn, would result in a reduction of the Company's revenues. The ability of these third parties to execute projects and market oil and natural gas from the Royalty Properties depends upon numerous factors beyond such third parties' and the Company's control, including the risk factors set out below. Because of these factors, these third parties could be unable to execute projects on the Royalty Properties on time, on budget, or at all, and may be unable to produce and market the oil and natural gas from the Royalty Properties effectively, all of which would result in a reduction of the Company's associated revenues.

In addition, due to volatile commodity prices, many companies, including companies that are lessees on the Fee Lands or working interest owners on the Royalty Properties, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. Continued volatile commodity prices may also result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which the Company has a royalty interest will negatively affect the Company's business, financial condition, results of operations and prospects.

Further, any financial difficulty of companies who are lessees on the Fee Lands or working interest owners on the Royalty Properties may affect the Company's ability to collect royalty payments especially if such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy, insolvency or creditor protection, including as a result of the AB LMF resulting from the Redwater Decision. See "*Risk Factors – Third Party Credit Risk*".

Commodity Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net royalty production revenue, royalty production volumes and development and exploration activities on the Royalty Properties.

The Company’s revenue, cash flow, profitability, financial condition and financial performance are highly dependent on commodity prices. Historically, crude oil, natural gas and NGL markets have been volatile and are expected to continue to be volatile in the future. Crude oil, natural gas and NGL prices are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of other factors that are beyond the Company’s control. The ability to market crude oil, NGL and natural gas from the Royalty Properties may depend upon the ability of third-party operators to acquire capacity in pipelines that deliver crude oil, NGL and natural gas to commercial markets or contract for the delivery of crude oil and NGL by rail (see "*Industry Conditions – Pricing and Marketing in Canada*” and "*Industry Conditions – Pipelines*"). Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of crude oil, NGL and natural gas acquired, produced, or discovered on, the Royalty Properties, including:

- deliverability uncertainties related to the distance the reserves on the Royalty Properties are from pipelines, railway lines, and processing and storage facilities;

- operational problems affecting pipelines, railway lines and processing and storage facilities;

- technological innovations and financial conditions affecting production volumes and costs; and

- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of world economies, actions of OPEC+, political uncertainties, the continuation or implementation of any tariffs, surtaxes or other restrictive trade measures or countermeasures, including the introduction of regulatory barriers to trade, sanctions imposed on certain oil producing nations by other countries, the Russian Ukrainian war, conflicts in the Middle East, geopolitical tensions between the United States and Venezuela, and other adverse economic or political developments in the United States, Europe, or Asia. Additionally, the occurrence or threat of terrorist attacks could adversely affect the global economy.

Prices for oil and natural gas are also subject to the availability of foreign markets and the ability of third parties operating on the Royalty Properties to access such markets. To the extent that political actions taken in North America, South America, Europe, the Middle East 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 Company's business and the operations of third parties on the Royalty Properties could increase and access to skilled labour could decrease.

Limitations on the ability of Western Canadian energy producers to export crude oil, NGL and natural gas to U.S. markets and other world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to U.S. and international benchmark commodity prices could negatively impact the Company'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.

A material decline in prices or a continued low oil and natural gas price environment could result in a reduction of the Company's anticipated royalty production revenue associated with the Royalty Properties. 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 of the reserves associated with the Royalty Properties. Lessees on the Royalty Properties may also elect, pursuant to the terms of the leases, during the primary term not to produce from certain wells at lower prices, which, in turn, would reduce the Company's royalty production revenues. Any substantial and extended decline in or continued low oil and natural gas prices would have an adverse effect on the third-party operators on the Royalty Properties and may impact the Company’s carrying value of its Royalty Properties, profitability and cash flow which may have a material adverse effect on the Company’s business and financial condition. See "*Industry Conditions – Pricing and Marketing in Canada*" and "*Industry Conditions – Pipelines*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers, sellers, lessors and lessees 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 developments, acquisitions, divestitures or leasing opportunities.

Third Party Exploration, Development and Production Risks

The Company's future performance may be affected by the financial, operational, environmental, seasonal and safety risks associated with the exploration, development and production of oil and natural gas.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to enter into lease and royalty arrangements with exploration and production companies and promote the exploration for and development and commercial production of oil and natural gas on the Company's properties by these lessees, as well as to acquire additional oil and natural gas assets to contribute to additional oil and gas reserves. A future increase in the Company's reserves will also depend on the ability of the Company to encourage further exploration on and development of the Royalty Properties by third parties. Without the continual addition of new reserves, the Company's reserves and related royalty revenue stream will decline over time as the lessees produce from such reserves. There is no assurance that the Company will be able to continue to find satisfactory third-party exploration and production companies to develop and/or operate on the Royalty Properties or to otherwise acquire additional oil and natural gas assets to contribute additional reserves. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that these lessees will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration on the Royalty Properties may involve unprofitable efforts from dry wells or wells that are productive but do not produce sufficient oil and natural gas substances to return a profit to a third party 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, which may result in decreased activities on the Royalty Properties by third parties resulting in less revenue to the Company.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations of third parties on the Royalty Properties and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in 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 a third party's production from the Royalty Properties, which may reduce the Company's revenue.

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, the environment and cause personal injury or threaten wildlife. Particularly, operators on the Royalty Properties may explore for and produce sour natural gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the third parties on the Royalty Properties, which, in turn, may result in liability to the Company.

Oil and natural gas production operations are also subject to geological and seismic risks including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a negative effect on production from the Royalty Properties, which negative effect could prove to be material over time and which may reduce the Company's revenue.

Seasonal weather patterns also influence oil and natural gas operations in Canada. Road bans, seasonal accessibility of sites, extreme cold weather, heavy snowfall, heavy rainfall, severe storms and other seasonal weather variations generally result in a reduction of extraction and exploratory activities and may also result in the shut-in of production by third parties on the Royalty Properties, which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

Tariffs and Trade Relations

The Company's business may be materially adversely affected by the continuation or implementation of any tariffs, surtaxes, or other restrictive trade measures or countermeasures.

Recent developments in U.S.–Canada trade relations, including the threat and, in some cases, the imposition of tariffs on certain Canadian goods, highlight the uncertainty associated with international trade policy. In addition, the United States Mexico Canada Agreement (the *USMCA*), which requires the three signatory countries to hold a joint review of the agreement every six years, is scheduled for July 1, 2026. As 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, any changes to, or failure by one or more parties to comply with, the USMCA could have an impact on Western Canada's oil and natural gas industry at large, including the Company's business. Potential measures could include increased tariffs on Canadian energy exports, restrictions on cross-border supply chains, or additional regulatory barriers to trade.

The continuation or implementation of any tariffs, surtaxes or other restrictive trade measures or countermeasures, including the introduction of regulatory barriers to trade, could have a significant impact on the market for oil and natural gas products, including cost and price volatility, a relative weakening of the Canadian dollar, widening differentials, decreased demand for the products of third parties operating on the Royalty Properties, and increased costs for equipment, infrastructure, and maintenance. Any such measures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Developments in U.S.-Canada trade relations may also have implications on many of the top and emerging risks to which the Company is exposed. The extent to which the Company's business, financial condition, results of operations and prospects will be affected depends largely on the nature and duration of uncertain and unpredictable events, such as the duration or escalation of the tariffs, the evolution of retaliatory measures, possible fiscal or monetary policy responses, and reactions to ongoing changes by global financial markets.

International Conflicts and Geopolitical Risk

The Company's business may be adversely affected by geopolitical conflicts abroad.

Conflicts, or conversely peaceful developments in conflicts and geopolitical matters, arising in commodity producing regions such as the Middle East, Venezuela and Russia may affect global economic conditions, oil and natural gas supply and demand, commodity pricing, transportation and shipping, and capital markets, and may result in a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Throughout 2025, conflict has continued in various commodity producing regions, with the potential for escalation and intervention by Western countries, including the United States. These developments heighten the risk of volatility and disruptions in global oil and natural gas markets, including through potential impacts on crude oil production and exports, the imposition or expansion of international sanctions, retaliatory actions, or broader regional and international instability among nations with interests in conflicted regions.

The ultimate impact of these conflicts and geopolitical events on global oil and natural gas markets remains uncertain. Any further escalation of these tensions, or other geopolitical conflicts including, but not limited to, oil-producing or energy-transit regions, could increase volatility in energy markets and result in a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Political Uncertainty

The Company's business may be materially adversely affected by recent political and social events and decisions made in Canada and elsewhere.

The Company may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could negatively impact the oil and natural gas industry and create uncertainty in the market. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits or restrict the operation of third-party infrastructure projects. Additionally, changes in environmental laws and regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders and consensus seeking with Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and materially adversely impact the Company's business, financial condition, results of operations and prospects.

With the election of a minority federal government in 2025, there remains uncertainty within the Canadian political landscape. The applicability and final form of proposed federal regulations that have not yet been enacted, including those relating to carbon pricing, emissions caps and methane management, remain subject to legislative negotiation and may evolve through the parliamentary process. Along with the Trump administration in the United States, this could lead to a policy shift that could impact the regulatory environment of the oil and natural gas industry and may have a material adverse impact on the Company's business, financial condition, results of operations and prospects.

Other government and political factors that could have a material adverse effect on the Company's business, financial condition, results of operations and prospects include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could reduce the demand for crude oil, natural gas and NGL. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease expected revenues from operations conducted by third parties on Royalty Properties.

In November 2022, Premier Danielle Smith introduced Bill 1: *Alberta Sovereignty Within a United Canada Act* (the *Sovereignty Act*). The *Sovereignty Act* received Royal Assent on December 15, 2022. The *Sovereignty Act* enables the Alberta government to direct provincial authorities and entities to limit or withdraw participation in the administration, implementation, or provincial cooperation with certain federal legislation, policies or programs that the Alberta government considers harmful to Alberta's interests or unconstitutional. The practical impact of the *Sovereignty Act* on Alberta businesses, including those in the oil and natural gas industry, as well as on Alberta's intergovernmental relationships, remains uncertain. In May 2025, the Onion Lake Cree Nation publicly stated its intention to advance previously filed legal proceedings challenging the *Sovereignty Act* on the basis that it infringes upon treaty rights. No court has ruled on the merits of such challenges to date. The *Sovereignty Act* may also be subject to additional constitutional challenges in the future.

A change in federal, provincial, state or municipal governments in Canada or the United States may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic, resulting in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the activities of third parties operating on the Royalty Properties. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*" and, "*Industry Conditions – Pipelines*", and "*Industry Conditions – The United States Mexico Canada Agreement and Other Trade Agreements*".

Information Technology Systems and Cyber-Security

Breaches of the Company's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

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

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

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 the Company's systems and obtain confidential information. The Company periodically reviews, supervises, retains and maintains the ability to retrieve social media content. 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 the Company 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.

The Company maintains policies and procedures, including a cyber-security incident response plan, which address and implement employee protocols with respect to electronic communications and electronic devices and conducts periodic cyber-security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such cyber-phishing attacks through education and training, phishing activities remain a serious problem that may damage the Company's information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches and the measures, controls and technology on which the Company relies are constantly evolving, and therefore they may not be adequate due to the increasing volume, sophistication and rapidly evolving nature of cyber-threats. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's reputation, performance and earnings, which negative effect could prove to be material over time, and any damages sustained may not be adequately covered by the Company's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The increasing prevalence of artificial intelligence (*AI*) may also increase the risk of cyber-attacks or data breaches as a result of the use of AI to launch more automated, targeted, and coordinated attacks to the Company’s technology infrastructure.

Global Financial Markets

The Company's business may be materially adversely affected by ongoing financial conditions and market events.

Market events, geopolitical tensions, and economic uncertainties in recent years have, among other things, resulted in significant volatility in commodity prices. Oil and natural gas prices are expected to remain volatile in the near term due to market uncertainties regarding the supply and demand fundamentals for oil and natural gas products due to the current state of the world's economies, actions taken by OPEC+, the ongoing risks facing North American and global economies and increased supplies of oil and natural gas which may be created by the application of new drilling technology to unconventional resource plays.

Credit Facility Arrangements

Failing to comply with covenants under the Credit Facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder.

The Company is required to comply with covenants under its Credit Facility which include certain financial ratio tests, which from time to time either affect the availability or price of additional funding and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with any of the covenants could result in an event of default which, if not cured or waived, would permit acceleration of repayment of the indebtedness pursuant to the Credit Facility and may prevent dividends from being paid to shareholders. The acceleration of repayment of the Company's indebtedness under the Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility imposes certain operating and financial restrictions on the Company that include restrictions on the payment of dividends, limitations on liens, entering into disposition of assets or amalgamations and restrictions on speculative hedging, among others. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to the Company. Failure to comply with debt covenants or negotiate relief, may result in the Company's indebtedness under the Credit Facility becoming immediately due and payable, which may have a material adverse effect on the Company's business and financial condition.

Inflation and Cost Management

Third-party operations on the Royalty Properties may be negatively impacted by inflationary pressures resulting in operational delays, cost overruns and reduced drilling activity on the Royalty Properties.

Third-party production companies' operating costs could escalate and become uncompetitive due to supply chain disruptions, tariffs, surtaxes or other restrictive trade measures or countermeasures, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations, which may reduce the Company's revenue. Third party production companies' inability to manage costs of their business, including future capital expenditures and recurring costs to operate, may impact project returns and future development decisions, which, in turn, could have a material adverse effect on the Company's business and financial condition.

The cost or availability of oil and natural gas field equipment may adversely affect third party production companies' ability to undertake exploration, development and construction projects. 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. A failure by third-party production companies to secure the services and equipment necessary to their operations on the Royalty Properties for the expected price, on the expected timeline, or at all, may have a material adverse effect on the Company's business and financial condition.

Project Risks

The success of third-party operations on the Royalty Properties may be negatively impacted by factors outside of the third-party operators' or the Company's control resulting in operational delays and cost overruns.

Third-party operators manage a variety of small and large projects on the Royalty Properties. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The ability of third-party operators to execute projects on the Royalty Properties and to successfully market oil and natural gas depends upon numerous factors beyond the third-party operator's or the Company's 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, and waterfloods or the third-party operator's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental laws and regulations;
- effects of inclement and severe weather events and natural disasters, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;

- currency fluctuations;
- regulatory changes;
- political uncertainty;
- availability and productivity of skilled labour;
- environmental and Indigenous activism or land claims that potentially result in delays or cancellations of projects;
- litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

If cash flow from operating activities and funds from external financing sources are not sufficient to cover a third-party operator's capital expenditure requirements, the third-party operator may be required to reallocate available capital among their projects or modify their capital expenditure plans, which may result in delays to, or cancellation of, certain projects or deferral of certain capital expenditures. Any change to a third-party operator's capital expenditure plans could, in turn, have a material adverse effect on their growth objectives and business, financial position and results of operations. Because of these factors, third-party operators could be unable to execute projects on time, on budget, or at all which could negatively impact the Company's royalty production volumes and future development activity on the Royalty Properties, which negative impact could prove to be material over time.

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel could negatively impact the Company's operations.

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

There is competition for qualified personnel in the oil and natural gas industry and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. In addition, certain of the Company's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Company is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Company could be negatively impacted, which negative impact could prove to be material over time. In addition, the Company could experience increased costs to retain and recruit these professionals.

Third-Party Credit Risk

The Company is exposed to credit risk of third parties on the Royalty Properties.

The Company may be exposed to third-party credit risk through its royalty and contractual arrangements with the third parties on the Royalty Properties, including operators of the properties, marketers of its oil and natural gas take-in-kind volumes, if any, and other industry participants. In the event such entities fail to meet their royalty, contractual or financial obligations to the Company, such failures could materially adversely affect the Company's business and financial condition. Further, poor credit conditions may impact a third party's ability to fund the development and capital programs conducted on the Royalty Properties, which in turn could result in a reduction of the Company's revenues. In addition, poor credit conditions in the industry, generally, and of any third parties on the Royalty Properties may affect such third party's willingness to participate in the ongoing capital program on such Royalty Properties, potentially delaying the program and the results of such program until such third party finds a suitable alternative partner.

To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's business and financial condition. See "*Risk Factors – Dependence on Lessees and/or Operators*" and "*Risk Factors – Commodity Prices, Markets and Marketing*".

Alternatives to and Changing Demand for Oil and Natural Gas Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's business and financial condition.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and renewable energy generation systems could reduce the demand for crude oil, natural gas and NGL. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels, commitments to carbon reduction and encourage the use of renewable fuel alternatives, which may lessen the demand for oil products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for crude oil, natural gas and NGL. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a negative impact on the Company's business and financial condition by decreasing the Company's royalty revenues, limiting its access to capital and decreasing the value of its assets.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Company's financial condition.

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 may indirectly negatively affect the Company's revenues, as revenues received by Canadian producers and, similarly, royalties payable to the Company, could decrease. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent reserves evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively impact the price the Company and the lessees and/or operators of Royalty Properties receive for oil and natural gas production, it could also result in an increase in the price of certain goods used by lessees and operators of the Royalty Properties in their operations which may have a material negative impact on the Company's business and financial condition. Where the Company engages in risk management activities related to foreign exchange rates, there is a potential credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its activities and the cash available to pay dividends, and could negatively impact the market price of the Common Shares, which negative impact could prove to be material over time.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on third parties' ability to produce and sell their oil and natural gas, as well as for the Company to sell production volumes it takes in-kind.

The products produced from the Royalty Properties must be delivered through gathering and processing facilities and pipeline systems, none of which are owned by the Company and some of which are not owned by the third parties active on the Royalty Properties, and in certain circumstances, by rail. The amount of oil and natural gas produced and sold from the Royalty Properties is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the inability of third parties to realize the full economic potential of the produced oil or natural gas or a reduction of the price offered for the production from the Royalty Properties. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work, natural disasters and environmental conditions, or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition. As a result, producers have considered rail lines as an alternative means of transportation.

Future pipeline projects may be terminated for reasons such as a failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Company is unknown.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. In the fall of 2023, the SCC found aspects of the IAA to be unconstitutional and the federal government amended the IAA in June 2024 in an effort to make it compliant. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". Projects that are subject to an impact assessment under both provincial and federal legislation, will likely be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of the proposed project subject to the legislation. In addition, the effects of projects on Indigenous communities and their constitutionally protected rights may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation. The federal government has recently announced initiatives to support and facilitate priority infrastructure projects, namely the implementation of the Building Canada Act, the formation of the MPO and the Canada-Alberta MOU. See "*Industry Conditions – Pipelines*".

The production from the Royalty Properties is processed through facilities owned by third parties over which the Company, and in certain instances, the third parties on the Royalty Properties, have no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the ability of the third parties to process production from the Royalty Properties and to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. 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.

For royalty payments taken-in-kind by the Company, the ability of the Company or a third-party marketer to successfully market in-kind oil and natural gas products may depend, in part, on the Company's or the third-party marketer's ability to acquire space on pipelines that deliver oil and natural gas to commercial markets. Deliverability uncertainties related to the distance the Company's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities, as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and other aspects of the oil and natural gas industry may also affect the Company. See "*Risk Factors – Commodity Prices, Markets and Marketing*".

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase costs and/or delay planned operations on the Royalty Properties.

The implementation of new laws and regulations or the modification of existing laws and regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase costs or make certain projects on the Royalty Properties uneconomic, either of which could materially adversely affect the Company's business and financial condition. Shifts or changes in governmental policy, including as a result of new or existing administrations in the jurisdictions in which the Company conducts its business may have an impact on the laws and regulations affecting the oil and natural gas industry, as well as the Company. Further, third-party challenges to regulatory decisions or orders can reduce the efficiency of the regulatory regime by delaying decisions resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*", and "*Industry Conditions - Pipelines*".

In order to conduct oil and natural gas operations, third-party lessees and/or operators on the Royalty Properties will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that third-party lessees and/or operators will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake in the time required or on acceptable terms and conditions. Any failure to renew, maintain or obtain required permits, licences, registrations, approvals and authorizations or the revocation or termination of existing permits, licences, registrations, approvals and authorizations may disrupt such third-party lessee and/or operator operations and could have a resulting material adverse effect on the Company's business and financial condition. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Programs*".

Environmental

Compliance with environmental regulations requires the dedication of a portion of the financial and operational resources of the lessees and/or operators of the Royalty Properties.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental laws and regulations 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 oil 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. Shifts or changes in governmental policy, including as a result of new or existing administrations in the jurisdictions in which the Company conducts its business may have an impact on the environmental laws and regulations affecting the oil and natural gas industry, as well as the Company. See "*Industry Conditions – Pricing and Marketing in Canada – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

As a royalty interest holder, the Company does not operate or control energy resource activities and the Company believes it has minimal or no direct exposure to environmental claims and regulation or the associated costs in the jurisdictions where the Royalty Properties are situated, subject to the recent amendments to British Columbia's energy legislation that provides regulators with discretion to impose environmental and remediation obligations on persons with a legal or beneficial interest in production or profits from such activities. The Company believes its risk of being subject to such obligations in British Columbia is low. Nonetheless, regulatory interpretation and enforcement of these provisions may evolve and there can be no assurance that environmental claims or regulatory liabilities will not be asserted in the future.

Environmental claims and regulatory liabilities directly impact the lessees and/or operators of the Royalty Properties. 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 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 lessee or operators of the Royalty Properties to incur costs to remedy such discharge. The Company requires the lessee or operators of the Royalty Properties to be in material compliance with current applicable environmental legislation; 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 associated with the Royalty Properties or otherwise have a negative effect on the Company's business and financial condition, which negative effect could prove material over time.

Stakeholders, Indigenous communities, 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. Operations conducted by third-party operators may disturb the surrounding biodiversity of the Royalty Properties with the requirement for earth moving and the footprint of oil and natural gas operations. This may result in impacts to flora and fauna, including species at risk. Operations on the Royalty 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 Royalty Properties. Third-party operators 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 Royalty Properties. There is no assurance that third-party operators on the Royalty Properties will effectively limit habitat destruction or mitigate the impacts on biodiversity on the Royalty Properties. If they fail to do so, there may be decreased activities on the Royalty Properties, which could have an adverse effect on the Company's business and financial condition. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*".

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with a third party's ability to acquire properties or require a substantial cash deposit with applicable regulators, which may affect the Company's business and financial condition.

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. In these jurisdictions, the abandonment, remediation and reclamation liability regimes include orphan well funds that are funded through a levy imposed on licensees, including the third-party lessees or operators, based on the licensees' proportionate share of the deemed abandonment, remediation and reclamation liabilities for oil and gas facilities, wells and unreclaimed sites. The regulators in these jurisdictions may seek additional funding for such liabilities from industry participants. In addition, the new AB LMF may add additional uncertainty around the quantum of security deposits and regulatory approval of transactions, as compared to the previous AB LLR program. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Programs – Alberta*".

The abandonment, remediation and reclamation regimes in these jurisdictions may impose an increase in financial disclosure obligations or result in the denial of license or permit transfers, which could impact the availability of capital to be spent by third party lessees or operators on the Royalty Properties, which in turn could materially adversely affect the Company's business and financial condition. Although the AER has implemented changes in response to the Redwater Decision, the impact on lending practices in the oil 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 abandonment, remediation and reclamation regimes in these jurisdictions may affect a third party's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Programs*".

Royalty Regimes

Changes to royalty regimes may negatively impact the Company's cash flows and earnings.

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of third-party projects on the Royalty Properties. An increase in royalties could impact the financial condition of third parties operating on the Royalty Properties impacting future capital investment which could reduce the Company's business, financial condition, results of operations and prospects. British Columbia introduced a new royalty framework in May 2022 under a transition period September 1, 2022 to August 31, 2024, which has now been extended until December 31, 2026. Pursuant to the transition period, additional provisions have been implemented for oil wells and dry natural gas wells with a spud date on or after September 1, 2024. The new royalty framework in British Columbia will take effect as of January 1, 2027. See "*Industry Conditions – Royalties and Incentives*".

Climate Change

Climate change may pose varied and far-ranging risks to the business and operations of third parties, both known and unknown, which may directly affect the Company's business and financial condition.

There is growing international and domestic concern regarding climate change and a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, non-governmental organizations (*NGOs*), environmental and governance organizations, institutional investors, social and environmental activists, shareholders and individuals are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively, are intended to or have the effect of accelerating the reduction in the global consumption of fossil fuel-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from fossil fuel based forms of energy.

Climate change and its associated impacts may increase the Company's exposure to, and magnitude of, each of the risks identified in this AIF. The Company is unable to estimate the degree to which climate change-related regulatory, climatic conditions, and climate-related transition risks could affect third parties operating on the Royalty Properties as well as the Company's business, financial condition, results of operations and prospects. See "*Industry Conditions – Climate Change Regulation*".

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. 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 subsidies, prohibitions on and monitoring of 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. Accordingly, there is a risk that the nature of the global energy transition could have a material adverse affect on the Company's business and financial condition.

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 of some of the Company's royalty payors, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Company'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 Company, for alleged personal injury, property damage, or other potential liabilities. While the Company 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 Company, 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. These developments may require the Company's management to dedicate significant time and resources to these climate change-related concerns, which may adversely affect the demand for and price of the Company's securities and the Company's cost of capital and access to the capital markets, which negative impacts could prove to be material over time.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to ESG and climate reporting, on June 26, 2023, the International Sustainability Standards Board issued its first two IFRS Sustainability Disclosure Standards, IFRS S1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and IFRS S2 - *Climate-related Disclosures*, with the purpose of developing sustainability disclosure standards that are globally consistent, comparable, transparent and reliable. Similarly, using the IFRS Sustainability Disclosure Standards as a baseline, the Canadian Sustainability Standards Board released its own two sustainability disclosure standards modified for the Canadian context, the Canadian Sustainability Disclosure Standard 1 - *General Requirements for Disclosure of Sustainability-related Financial Information* and Canadian Sustainability Disclosure Standard 2 - *Climate-related Disclosures*.

In addition, the Canadian Securities Administrators (the *CSA*) previously began developing 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. In April 2025, the CSA paused its work on this instrument, stating its intention to revisit the project in the future. If the Company 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 its ability to 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 Company'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 Company's royalty payors to access their 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 third-party operations on the Royalty Properties.

Chronic Physical Climate Change Risks

Third-party operations and activities associated with the Royalty Properties emit GHGs which may require parties leasing and/or operating the Royalty Properties 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 Company'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 oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. 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 leasing or operating parties on the Royalty Properties 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 production from the Royalty Properties, which negative effect could prove material over time. Specifically, in the event of water shortages or sourcing issues, third parties operating on the Royalty Properties 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 production of crude oil, natural gas and NGL from third-party producers, which would have a material adverse effect on the Company's business, financial condition, results of operations and prospects. See "*Risk Factors – Alternatives to and Changing Demand for Oil and Natural Gas 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 Company's operating expenses and in the long-term, potentially reducing the demand for oil and natural gas production resulting in a decrease in the Company'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 operations of third-parties on the Royalty Properties, increasing costs and negatively impacting the lessee or third-party operator's production. Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires and flooding, most recently with wildfires in Alberta, causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in a third-party's ability to transport produced oil and natural gas as well as goods and services in their supply chains and meet demand due to temporary interruptions.

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

Exposure to Widespread Pandemic and Risks Related Thereto

The Company's business may be materially adversely affected by widespread global pandemics.

Pandemics, epidemics or outbreaks and their ultimate impact are highly uncertain and subject to change. A pandemic and the corresponding measures we take to protect the health and safety of the Company's staff and the continuity of Company's business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims. Actions taken by various levels of government and health authorities in the event of a pandemic, epidemic or outbreak may result in a reduction in the demand for, and prices of, commodities that are closely linked to the Company's financial performance and may negatively impact the Company's business, results of operations and financial condition. The Company may also be exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures which may be implemented in response to a pandemic.

Natural Disasters, Terrorist Acts, Civil Unrest and Other Disruptions and Dislocations

Events such as natural disasters, terrorist acts, global pandemics and other disruptions may pose varied and far-ranging risks to the business and operations of third parties, both known and unknown, which may directly affect the Company's business and financial condition.

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Company. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses, civil unrest and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes for third parties, adversely affecting the Company's financial position.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing on the Royalty Properties. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that is ultimately produced from the reserves associated with the Royalty Properties and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Third-party operators on the Royalty Properties may face operational delays if found to be not strictly compliant with the current regulatory framework.

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact third-party operations on the Royalty Properties and recovery from waterfloods.

Third-party operators on the Royalty Properties may undertake or intend to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase recovery from the reservoir and to decrease production declines. To undertake such waterflooding activities, third-party operators need access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase or maintain the pressure in the reservoir. Waterflood operations in Western Canada primarily utilize recycled produced water which may be supplemented with water from dedicated source wells targeting deep (subsurface) saline aquifers. While these sources are typically sufficient for waterflooding activities, there is no certainty that third-party operators will have access to the required volumes of water. If third-party operators are unable to access such water they may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company will ultimately receive from the Royalty Properties' reservoirs. In addition, third-party operators may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's business, financial condition, results of operations and prospects.

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in operations by third parties may increase costs of compliance or subject third-party operators on the Royalty Properties to regulatory penalties or litigation.

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 for third-party operators on the Royalty Properties which may impact the economics of certain projects and in turn impact activity levels and new capital spending on the Royalty Properties.

Title to Assets

Defects in title to the Company's properties may result in a financial loss.

Although title reviews may be conducted prior to the purchase of fee simple mineral title interests or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise to defeat the Company's claim. The actual interest of the Company in the Royalty Properties may, therefore, vary from the records previously maintained by the prior owners. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which could materially adversely affect the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the Royalty Properties that, if successful or made into law, could impair the Company's royalty interests and impact the Company's business, financial condition, results of operations and prospects.

Other Title Risks, including those applicable to Gross Overriding Royalties

Defects in title to the GORR Interests may result in a financial loss.

The majority of the Company's GORR Interests attach to licences and leases and working interests in licences and leases. If the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire thereby terminating the Company's GORR Interest. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of a licence or lease or the working interest relating to a licence or lease may have a material adverse effect on the Company's results of operations and business. In addition, title to the properties can become subject to dispute and defeat the Company's claim to title over certain of its properties. Furthermore, there may be valid challenges to title or proposed legislative changes which affect title to the leases and licences to which the Company's GORR Interests attach that, if successful or made into law, could impair its royalty interests and impact the Company's business, financial condition, results of operations and prospects.

Non-Governmental Organizations

The Royalty Properties and nearby facilities may be subject to action by non-governmental organizations.

The oil and natural gas industry 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 third-party operators on the Royalty Properties to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups which may include Indigenous communities, 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, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation (see "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*"). There is no guarantee that third-party operators on the Royalty Properties 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 Company's business, financial condition, results of operations and prospects, which negative impact could prove to be material over time.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede third parties' exploration, development and operating activities, which may affect the Company's business and financial condition.

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 third-party operations on the Royalty Properties and may delay such exploration, development and operating activities, which, in turn, could materially adversely affect the Company's business and financial condition.

Diluent Supply

A decrease in, or restriction in access to, diluent supply may reduce the Company's royalty revenues.

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market would reduce the Company's overall royalty revenues.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas and the operating costs for third-party operators on the Royalty Properties and may impair their ability to compete.

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. There is also uncertainty regarding what impacts the current minority federal government and recently announced Climate Competitiveness Strategy will have on emissions reduction and carbon pricing policies in Canada. 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 the operating expenses of oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue from the Royalty Properties. Further, the imposition of carbon taxes puts companies at an economic disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Insurance

Not all business risks are insurable and the occurrence of an uninsurable event may have an adverse effect on the Company.

Although the Company maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums or retentions associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The lessees of the Royalty Properties may fail to meet the requirements of a licence or lease, causing its termination or expiry.

Certain of the Company's Royalty Properties are tied to licences and leases and working interests in licences and leases. If the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of these licences or leases or the working interests relating to a licence or lease may impair certain of the Company's royalty interests and in turn may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Litigation

The Company may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Company and its reputation.

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to property damage, personal injury, tax, land rights, royalty rights, access rights, environmental issues, including related to climate change and the impacts thereof, lease or contract disputes, breach of contract, common law duties, regulatory enforcement actions, *Competition Act* enforcement actions, patent infringement, disclosure, and in relation to an attack, breach or unauthorized access to the Company's information technology and infrastructure. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty, may be determined adversely to the Company and could have a material adverse effect on the Company's business, financial condition and funds from operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's reputation, business and financial condition.

Indigenous Claims

Indigenous claims and interpretation of historical treaties may affect the Company.

Indigenous Peoples have claimed Indigenous title and rights to portions of Western Canada. In particular, certain aboriginal groups have challenged title to lands near the Fee Lands and the GORR Lands. Claims and protests of Indigenous Peoples may disrupt or delay third-party operations, new development or new project approvals on the Royalty Properties. The Company is not aware of any claims that have been made in respect of its properties and assets; however, if a claim arose and was successful, such claim may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

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 communities 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. The requirement to consult with Indigenous Peoples in respect of oil and gas projects and related infrastructure have increased in recent years.

On August 7, 2025, the British Columbia Supreme Court, in *Cowichan Tribes v Canada (Attorney General)*, recognized Aboriginal title for the Cowichan Tribes over a defined parcel of land on unceded territories in Richmond, British Columbia, an area that includes fee simple lands held privately. While the potential impact of current and future judicial decisions remains uncertain, including the full legal and practical implications for mineral, oil, gas, and other private land operations, it is possible that such decisions may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. See "*Industry Conditions - Indigenous Rights*".

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved, and the Company may dispose of certain non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

While management is focused on encouraging third parties to develop the Royalty Properties, the Company also considers acquisitions and dispositions of certain royalty assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. Acquisitions are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding factors such as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future commodity prices, operating costs and capital expenditures and royalties and other government levies which may be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Company.

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 Company 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 Company, which could materially adversely affect the Company'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 Company 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 Company may realize less on disposition of certain non-core assets than their carrying value on the financial statements of the Company.

Competition

The Company competes with other entities to encourage the development of the Royalty Properties and to acquire additional royalty interests, some of which have greater financial resources, staff or political influence.

The oil and natural gas industry is highly competitive in all of its phases. The Company competes with numerous other entities to encourage third-party development of the Royalty Properties and to acquire additional oil and natural gas interests and to access and retain skilled technical personnel, among other things. The Company's competitors include other fee simple mineral title owners, exploration and production companies and the Provincial and Federal Crown, as the owners of the significant majority of mineral rights in Western Canada, any of whom may have more financial resources, staff or political influence than the Company. The Company's ability to increase its reserves and revenue streams in the future will depend not only on its ability to promote development of the Royalty Properties, but also on its ability to select other suitable producing properties or prospects for third-party exploratory drilling and further development.

Management of Growth and Integration

The Company may not be able to effectively manage the growth of its business.

The Company may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. In particular, the Company 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 Company 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 Company to deal with this integration and growth may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Reserves Estimates

The Company's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Company.

There are numerous uncertainties inherent in estimating reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this AIF are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves which are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- commodity prices;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures by the working interest owners thereon;
- marketability of oil and natural gas;
- royalty rates (which, in the case of the Company, generally consist of the royalties to be paid to the Company); and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For these reasons, estimates of the economically recoverable oil and 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. The Company's actual net production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof 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. Such variations could be material.

In accordance with applicable securities laws, GLJ, the Company's independent qualified reserves evaluator, has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows 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 cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the GLJ Report and such variations could be material. The GLJ Report is effective as of December 31, 2025, with a preparation date of January 19, 2026, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry.

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the 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 oil and natural gas commodity prices, and the securities of issuers involved in the 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 oil and natural gas issuers relative to other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of 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 Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Capital and Additional Funding Requirements

The Company may require additional financing from time to time to fund the acquisition of additional royalty interests and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

The Company's cash flow from the Royalty Properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Company may require additional financing, which may include financing for the acquisition of oil and natural gas assets. Future acquisitions and other expenditures will be financed out of cash flow from royalty revenues, borrowings and possible future equity issuances and the Company's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; the Company's credit rating (if applicable); interest rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and the Company's securities in particular. Failure to obtain financing on a timely basis could cause the Company to miss certain acquisition opportunities. Due to the conditions in the oil and natural gas industry and/or global economic and political conditions and the domestic lending landscape, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the cost and/or ability of 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 Company. 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 Company's access to additional financing may be affected. The inability of the Company to access sufficient capital for its operations could cause the Company to, amongst other things, miss certain acquisition opportunities and may materially adversely affect the Company's business and financial condition.

In addition, the future development of the Royalty Properties by third parties may require additional financing and there are no assurances that such financing will be available, and, if available, will be available upon acceptable terms to such third parties. Failure to obtain any financing necessary for such third parties' capital expenditure plans may result in a delay in development of the Royalty Properties.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Company's access to, and cost of, capital.

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of oil and natural gas products during production and transportation and constitutionally protected Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies tied to 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 Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry, and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment charge.

Reputational Risk

The Company relies on its reputation to continue its operations and to attract and retain investors and employees.

The Company's business, financial condition, results of 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 Company or as a result of any negative sentiment toward or in respect of the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns. Any environmental damage, loss of life, injury or damage to property caused by third-party operations on the Royalty Properties could damage the reputation of the lessees or operators of the Royalty Properties and, in turn, the Company, in the areas in which the Company holds Royalty Properties. Negative sentiment towards any of the lessees or operators of the Royalty Properties could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for those lessees or operators to operate their business and in residents in the areas where such lessees or operators are doing business opposing further operations by such lessees or operators in the area, which could negatively impact the Company's revenues, which negative impact could prove to be material over time. The Company's reputation could be affected by actions and activities of other corporations operating in the oil and natural gas industry, over which the Company has no control. If the Company, either directly or indirectly develops a reputation of having an unsafe workplace it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. In addition, environmental damage, loss of life, injury or damage to property caused by third parties operating on the Royalty Properties and/or indirectly by the Company's business could result in negative investor sentiment towards the Company. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate-related litigation against fossil fuel companies may indirectly harm the Company'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 Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Company's securities.

Dividends

The amount of and frequency at which future cash dividends are paid may vary and there is no assurance that the Company will pay dividends in the future.

The amount of future cash dividends declared and paid by the Company 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 Company; 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 Company's risk management activities or programs; the Company'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 Company, the Company's dividend policy and, as a result, future cash dividends could be reduced or suspended entirely, from time to time. The Credit Facility may prohibit the Company 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.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, 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. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price, liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in losses to shareholders.

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

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of the Company to make the necessary incremental royalty acquisitions to maintain or expand oil and natural gas reserves will be impaired. To the extent that the Company is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Share Repurchases

The amount of and frequency at which future share repurchases under the NCIB may vary and there is no assurance that the Company will complete share repurchases in the future.

The amount of share repurchases of Common Shares under the NCIB, if any, are 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 Company; 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 Company's risk management activities or programs; the Company's business plan, strategies and objectives; tax laws; foreign exchange rates; and interest rates. Depending on these and various other factors, many of which are beyond the control of the Company, the authorization of share repurchases by the Board could be reduced or suspended entirely, from time to time.

Foreign Exchange Risk on Dividends

Variations in foreign exchange rates may affect the amount of cash dividends received by shareholders who receive dividends in currencies other than Canadian dollars.

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Non-resident shareholders are required to pay additional taxes on their dividends.

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Where a non-resident is a United States resident entitled to benefits of the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%. In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

Hedging

Hedging activities may expose the Company to the risk of financial loss and counter-party risk.

The Company may enter into hedging arrangements to fix interest rates applicable to the Company's debt. However, if interest rates decrease as compared to the interest rate fixed by the Company, the Company will not benefit from the lower interest rate.

While the Company does not currently hedge against commodity price risk, the Company may in the future enter into agreements to receive fixed prices on its crude oil, NGL and natural gas royalty production volumes, if any, to offset the risk of revenue losses if commodity prices decline. Similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it 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, if the Company enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- 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; and/or
- a sudden unexpected material event impacts oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars 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, the Company will not benefit from the fluctuating exchange rate.

Income Taxes

Taxation authorities may reassess the Company's tax returns.

The Company files all required income tax returns in order to be in full compliance with the provisions of the *Tax Act* and all other applicable provincial tax legislation; however, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Issuance of Debt

Increased debt levels may impair the Company's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Company may finance its activities (including potential future oil and natural gas royalty asset acquisitions) in whole or in part with debt, which may increase the Company's debt levels above industry standards for peers of similar size. Additional debt financing may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Conflicts of Interest

Conflicts of interest may arise for the Company's directors and officers who are also involved with other industry participants.

Certain members of the Board and management are also, or may in the future be, directors or officers of other oil and natural gas companies, which may compete or be counterparties to agreements with the Company 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 ABCA and Company policies 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, or material transaction, or proposed material transaction, with the Company disclose their interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Company's competitive advantage or put it at risk of litigation.

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Company, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable solely in monetary damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Data Protection

The handling of secure information exposes the Company to potential data security risks that could result in monetary damages against the Company and could otherwise damage its reputation, and adversely affects its business, financial condition and results of operation.

The protection of customer, stakeholder, employee, and Company data is critical to the Company’s business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, stakeholder, employee, or Company data could attract a substantial amount of media attention, damage the Company’s customer relationships and reputation, and result in lost revenue, fines, or lawsuits. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Company to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Company may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its reputation, business, financial condition and results of operations.

Additionally, the Company's information technology systems may incorporate the use of AI and development of such capabilities remain ongoing. As with new innovations, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Company's business. AI algorithms and training methodologies may be flawed. The use of AI to support business of the Company, its partners, vendors, suppliers, contractors, or others carries inherent risks related to data privacy and cybersecurity, such as intended, unintended, or inadvertent transmission of proprietary or sensitive information, as well as challenges related to implementing and maintaining AI tools, including the development and maintenance of appropriate datasets for such support. Dependence on AI without adequate safeguards to make certain business decisions may introduce additional operational vulnerabilities, by producing inaccurate outcomes based on flaws or deficiencies in the underlying data or other unintended results. Further, AI tools or software may rely on data sets to produce derivative work which may contain content subject to license, copyright, patent or trademark protection or sensitive personal information and can produce outputs that infringe on intellectual property rights or compromise privacy of individuals or organizations, raising concerns about data privacy. As AI is an emerging technology for which the legal and regulatory landscape is not fully developed, including potential liability for breaching intellectual property or privacy rights or laws, new laws and regulations applicable to AI initiatives remains uncertain, and the Company's obligation to comply with such laws could entail significant costs, negatively affecting the Company's business or limiting the Company's ability to incorporate certain AI capabilities into its business.

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

Shareholders in the United States have a limited ability to enforce civil remedies against the Company in Canada.

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of the Company's directors and officers and the representatives of the experts who provide services to the Company (such as auditors and independent reserve engineers), and all or a substantial portion of the assets of such persons are 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 Company or against any of the Company's 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.

Negative Impact of Additional Sales or Issuances of Common Shares

The Company may issue additional Common Shares, diluting current shareholders.

The Board may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Company issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Common Shares could decline.

Forward-Looking Information

Forward-looking information may prove inaccurate.

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

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

Marketing Practices – Anti-Greenwashing Legislation

Changes to the Competition Act may increase both compliance costs and the risk of non-compliance that may have an adverse effect on the Company.

Recent updates to the Competition Act, which expand the Competition Act's deceptive marketing provisions, require businesses making environmental claims about products or business practices to substantiate their statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. As of June 20, 2025, private parties can bring deceptive marketing claims before the Competition Tribunal, a right previously exclusive to the Competition Bureau. In late 2025, Bill C-15 was introduced in the House of Commons, which, if enacted, would further amend the greenwashing provisions of the Competition Act, including by modifying substantiation requirements for certain environmental claims and limiting private access rights in respect of business-level environmental claims. See "*Industry Conditions – Climate Change Regulation*".

The Company's efforts to comply with these and other new and existing rules and regulations are likely to result in increased general and administrative expenses and a diversion of management's time and attention from revenue-generating activities to compliance activities. In addition, the Company may become involved in, named as a party to, or be the subject of, various legal claims and proceedings. The outcome with respect to such proceedings cannot be predicted with certainty, may be determined adversely to the Company and could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's business, financial condition, results of operations and prospects.

ESG and Sustainability

Increasing attention to ESG and Sustainability matters may impact the Company's business.

Companies across all industries, but particularly in the oil and natural gas industry, may face scrutiny from government and stakeholders related to their ESG and sustainability practices. Some capital markets participants use certain components of ESG as a factor in their valuation of companies, which could impact the Company's cost of capital or access to financing. There has also been an acceleration in investor demand for ESG investing opportunities, and many institutional investors have committed to increasing the percentage of their portfolios that are allocated towards ESG-focused investments. As a result, there has been a proliferation of ESG focused investment funds and market participants seeking ESG-oriented investment products. There has also been an increase in third-party providers of company ESG ratings and rankings, and an increase in ESG-focused voting policies among proxy advisory firms, portfolio managers, and institutional investors. Currently, there are no universal standards for such ratings, rankings and voting policies, they often differ based on the provider and the data they prioritize is continually changing; however, such ratings, rankings and voting policies may be used by some investors to inform their investment and voting decisions.

Additionally, certain investors may use these ratings or rankings to benchmark companies against their peers, and if a company is perceived as lagging, these investors may engage with the Company to require improved ESG disclosure or performance. Moreover, certain members of the broader investment community may consider a company's sustainability rating or ranking as a reputational or other factor in making an investment decision. Consequently, a low sustainability rating or ranking could result in exclusion of the Company's shares from consideration by certain investment funds, engagement by investors seeking to improve such ratings or rankings and a negative perception of the Company's business by certain investors. Additionally, to the extent ESG matters negatively impact the Company's reputation, it may not be able to compete as effectively to recruit or retain employees, which may adversely affect its operations. Furthermore, there has recently been backlash from certain governments and investors against ESG funds and investment practices, which has resulted in increased scrutiny and withdrawals from such funds. Such backlash has also resulted in "anti-ESG" focused activism and investment funds, which may result in additional strains on the Company's resources.

The Company also makes certain disclosures regarding sustainability from time to time, including publishing its Sustainability Report that provides updates on its performance related to certain ESG topics. Many of the Company's disclosures are necessarily based on estimates and assumptions that are inherently difficult to assess and may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Public statements with respect to ESG matters, including GHG emissions reduction goals, environmental targets, or, more broadly, ESG-related goals, are becoming increasingly subject to heightened scrutiny from public and governmental authorities with respect to the risk of potential "greenwashing," (i.e., misleading information or false claims overstating potential ESG benefits) and are now subject to greater scrutiny as a result of the enactment of Bill C-59, as discussed above. As a result, the Company may face increased litigation risks related to its ESG efforts which could, in turn, lead to further negative sentiment and diversion of investments. The Company could also face increasing costs to comply with increased regulatory focus and scrutiny. To the extent that the Company is unable to respond timely and appropriately to any negative publicity, its reputation could be harmed. Damage to its overall reputation could have a material adverse impact on the Company's business, financial condition, results of operations and prospects, including its share price, and require additional resources to rebuild the Company's reputation.

The Company may not be able to meet ESG targets in the manner, or on such a timeline as initially contemplated, including as a result of the significant time commitment from the Board, management and employees to implement such goals and policies, unforeseen costs, consequences or technical difficulties associated with achieving such results.

Description of Capital Structure

The authorized share capital of the Company includes an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series. As of the date hereof, 232,711,632 Common Shares and nil preferred shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and preferred shares.

COMMON SHARES

The rights, privileges, restrictions and conditions attaching to the Common Shares are set forth below.

Voting Rights

The holders of the Common Shares are entitled to one vote in respect of each Common Share held at all meetings of shareholders, except meetings at which only holders of a specified class of shares have the right to vote.

Dividends

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive any dividend declared by the Company on the Common Shares.

Rights upon Dissolution

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive the remaining property of the Company upon dissolution.

PREFERRED SHARES

The rights, privileges, restrictions and conditions attaching to the preferred shares are set forth below.

Preferred Shares

The Board may issue preferred shares at any time and from time to time in one or more series, and shall determine the rights, privileges, restrictions and conditions attached to each series of preferred shares before the issue of such series.

Dividends

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to payment of dividends.

Rights upon Dissolution

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to distribution of assets in the event of liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

Market for Securities

TRADING VOLUME AND PRICE

The Common Shares are listed and trade on the TSX under the symbol "PSK". The following table sets forth the high and low trading prices and the aggregate trading volume of the Common Shares on the TSX for the periods indicated.

Toronto Stock Exchange

	High ($/Common Share)	Low ($/Common Share)	Volume Traded
2025			
January	28.98	26.60	5,699,927
February	28.43	25.77	6,691,679
March	27.05	25.385	10,059,566
April	27.13	21.97	13,033,128
May	24.16	22.38	10,115,589
June	24.57	22.76	10,194,290
July	24.46	23.17	7,048,301
August	24.39	23.32	6,303,528
September	26.76	24.02	7,674,887
October	27.01	24.51	7,651,489
November	27.29	24.76	6,368,680
December	28.27	26.41	6,405,686
2026			
January	29.98	25.835	8,067,155
February (1-6)	30.55	28.91	2,339,651

In 2025, the Company purchased and cancelled an aggregate of 6,239,507 Common Shares at a weighted average price of $25.40 per Common Share for total consideration of $158.5 million, including commissions and before tax, under the Company's NCIB.

Dividends

In each quarter of 2025, the Board declared a dividend of $0.26 per Common Share or $1.04 on an annualized basis**.** On February 9, 2026, the Company announced that the Board had approved an increase in the annual dividend policy to $1.06 per Common Share on an annualized basis. The Board has approved the first quarterly dividend of $0.265 per Common Share effective for the March 31, 2026 record date. The Board reviews and determines changes to the dividend policy after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, and PrairieSky's capacity to fund operating and investing opportunities. The dividend policy is established with the intent of absorbing market volatility, including commodity price volatility, and maintaining a strong financial position to take advantage of strategic business development opportunities.

Dividends are paid quarterly to shareholders of record as of the close of business on the last business day of each quarter, with the 15th day (or next business day) of the following month being the corresponding payment date. Dividend payments are not guaranteed and the amount of cash to be distributed as dividends in the future may change. Any decision to pay dividends will be determined at the discretion of the Board after reviewing the overall dividend policy of the Company and after consideration of numerous factors including: (i) the earnings of the Company; (ii) financial requirements for the Company's operations; (iii) the satisfaction by the Company of liquidity and insolvency tests described in the ABCA; and (iv) any agreements relating to the Company's indebtedness that restrict the declaration and payment of dividends. The dividends paid on the Common Shares pursuant to the Company's dividend policy are designated as "eligible dividends" for Canadian income tax purposes, unless otherwise notified.

The per Common Share cash dividends set forth in the table below have been paid by the Company to its shareholders in the months indicated for the last three years.

Month of Dividend Payment Date	**Year 2023**	**2024**	**2025**
January	$0.240	$0.240	$0.250
February	-	-	-
March	-	-	-
April	$0.240	$0.250	$0.260
May	-	-	-
June	-	-	-
July	$0.240	$0.250	$0.260
August	-	-	-
September	-	-	-
October	$0.240	$0.250	$0.260
November	-	-	-
December	-	-	-

The historical cash dividend payments described above may not be reflective of future dividend payments, and future dividend payments are not assumed or guaranteed.

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, PrairieSky believes it may be classified as a passive foreign investment company (*PFIC*) under United States federal income tax principles. As such, dividends to taxable individual shareholders who are United States taxpayers should continue to be subject to the regimes of United States federal income taxation applicable to PFICs. Shareholders who are United States taxpayers should discuss with their tax advisors the reporting requirements with respect to owning shares in a PFIC. In order to allow shareholders the ability to make a Qualified Electing Fund election, PrairieSky posts annually a PFIC Annual Information Statement on its website. Shareholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from PrairieSky.

Directors and Executive Officers

BOARD OF DIRECTORS OF PRAIRIESKY

As at the date hereof, the Board is comprised of eight (8) individuals. The name, province of residence, principal occupation of each director of PrairieSky are set out below. The term of office of all directors of the Company will expire at the 2026 Annual General Meeting and, thereafter, at each annual meeting of shareholders of the Company or at the time at which his or her successor is elected or appointed, or earlier if any director otherwise dies, resigns, is removed or is disqualified.

Name, Province and Country of Residence	Principal Occupation	Director Since
Margaret A. McKenzie(1) Calgary, Alberta, Canada	Corporate Director	December 19, 2014
Anna M. Alderson(2)(4) Calgary, Alberta, Canada	Corporate Director	October 23, 2023
Anuroop S. Duggal(2)(3) Toronto, Ontario, Canada	Private Investor Corporate Director	April 18, 2023
Ian C. Dundas Calgary, Alberta, Canada	Corporate Director	January 1, 2026
P. Jane Gavan(2)(3) Toronto, Ontario, Canada	Corporate Director	May 23, 2019
Glenn A. McNamara(3)(4) Calgary, Alberta, Canada	Corporate Director	December 4, 2023
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer of the Company	April 11, 2014
Sheldon B. Steeves(3)(4) Calgary, Alberta, Canada	Corporate Director	April 11, 2014

Notes:
(1) Chair of the Board.
(2) Member of the Audit Committee. Ms. Alderson is the Chair of the Audit Committee.
(3) Member of the Governance and Compensation Committee. Mr. McNamara is the Chair of the Governance and Compensation Committee.
(4) Member of the Reserves Committee. Mr. Steeves is the Chair of the Reserves Committee.

EXECUTIVE OFFICERS OF PRAIRIESKY

The following table sets forth the name, province and country of residence, position(s) held with the Company and date of appointment of each of the executive officers of PrairieSky.

Name, Province and Country of Residence	Principal Occupation	Date of Appointment as an Officer
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer	April 11, 2014
Pamela P. Kazeil Calgary, Alberta, Canada	Senior Vice-President, Finance & Chief Financial Officer	June 1, 2015
Daniel J. Bertram Calgary, Alberta, Canada	Vice-President, Business Development & Chief Commercial Officer	October 10, 2023
Michael T. Murphy Calgary, Alberta, Canada	Vice-President, Geosciences & Capital Markets	January 29, 2024

As at the date hereof, the directors and executive officers of PrairieSky, as a group, beneficially own or control, directly or indirectly, 1.72 million Common Shares or approximately 0.7% of the issued and outstanding Common Shares.

DIRECTORS AND EXECUTIVE OFFICERS BIOGRAPHICAL INFORMATION

The following are brief profiles of each of the directors and executive officers of the Company, which include a description of their present occupation and their principal occupations for the past five years.

Margaret A. McKenzie

Ms. McKenzie's principal occupation is as a Corporate Director. Ms. McKenzie was the Vice-President, Finance and Chief Financial Officer of Range Royalty from 2006 to 2014 and prior thereto was Vice-President, Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and natural gas company). Ms. McKenzie holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan and has been a member of the Chartered Professional Accountants of Alberta since 1985. She obtained her ICD.D designation from the Institute of Corporate Directors in 2013 and was recognized as a Fellow of the Chartered Professional Accountants (FCPA) of Alberta in 2022. Ms. McKenzie is an experienced director and currently sits as a director of Canadian National Railway Company, a TSX- and NYSE-listed leader in North American transportation and logistics, Spur Petroleum Ltd. (private) and North 40 Resources Ltd. (private). Ms. McKenzie is also on the Board of Governors for Hull Services, a registered not-for-profit which has been helping Calgary's children, youth, and families navigate mental health challenges and other barriers since 1962.

Anna M. Alderson

Ms. Alderson is an experienced Corporate Director based in Calgary with over 35 years of experience in all sectors of the energy industry as well as financial services. Ms. Alderson retired from KPMG LLP in 2019 after a distinguished career as an audit partner in Calgary, Toronto and Hong Kong. Ms. Alderson is a Chartered Professional Accountant, holds her ICD.D designation from the Institute of Corporate Directors and earned a Bachelor of Commerce degree (with great distinction) from the University of Saskatchewan. Ms. Alderson is also a director of Tenaz Energy Corp., a TSX-listed oil and gas exploration company with assets in Canada and Europe. Ms. Alderson is a member of the audit committees of the Calgary Foundation and Calgary Exhibition & Stampede.

Anuroop S. Duggal

Mr. Duggal is a private investor since 2018 with significant institutional investing experience in the global energy sector. He was a partner at 3G Capital, a global multi-billion dollar asset manager, where he helped launch, manage and grow a natural resource focused equity and credit fund. Prior to that he was an investor with Goldman Sachs Investment Partners, which was the Asset Management division's flagship hedge fund. Mr. Duggal was also an Adjunct Professor for the MBA program at Columbia Business School where he taught value investing courses through the Heilbrunn Center for Graham & Dodd Investing for seven years. Mr. Duggal graduated from the University of Western Ontario with an Honors Business Administration degree (Richard Ivey School of Business, gold medalist) and an Electrical Engineering degree. Mr. Duggal also sits on the board of directors of Calfrac Well Services Ltd., a provider of specialized oilfield services, and Computer Modelling Group Ltd., a global software and consulting company to the energy industry, both of which are listed on the TSX.

Ian C. Dundas

Mr. Dundas' principal occupation is as a Corporate Director. He previously served as a Director and President & Chief Executive Officer of Enerplus Corporation (*Enerplus*) from 2013 until Enerplus combination with Chord Energy Corporation in May 2024. Mr. Dundas joined Enerplus in 2002 as Vice President of Business Development, responsible for corporate acquisition and divestment strategies. In

2011, Mr. Dundas was appointed Executive Vice President and Chief Operating Officer, where he oversaw the development and execution of Enerplus' operational strategies, strategic planning, marketing and reserves, as well as acquisitions and divestments.

In addition to PrairieSky, Mr. Dundas sits on the boards of Chord Energy Corporation, Impossible Sensing Energy Inc. and Sharptail Energy Inc. Mr. Dundas has been an active volunteer in numerous charitable endeavors and was Co-chair of the Calgary YMCA Power of Potential campaign. Mr. Dundas has previously served on the board of numerous private and public companies and industry trade organizations. Mr. Dundas holds a Bachelor of Commerce (Distinction) from the University of Calgary and a Bachelor of Laws (Distinction) from the University of Alberta. He was called to the Alberta Bar in 1995.

P. Jane Gavan

Ms. Gavan's principal occupation is as a Corporate Director. She has over 30 years of progressive experience in the real estate industry. Until her retirement in 2025, she held several leadership positions within the Dream group of companies, which companies operate in the real estate and asset management verticals in Canada, the U.S. and Europe. At various times in the last several years with the Dream group, she held the positions of President, Asset Management as well as CEO of three real estate investment trusts, all of which are or were listed on the TSX: Dream Global REIT; Dream Office REIT; and Dream Residential REIT. Ms. Gavan holds an Honours Bachelor of Commerce degree from Carleton University and a Bachelor of Laws degree from Osgoode Hall, York University. She was called to the bar in 1987.

In addition to PrairieSky, Ms. Gavan sits on the boards of Dream Unlimited, a real estate owner, developer and asset manager, Dream Office REIT, an owner and operator of office real estate, and Colliers International Group Inc., a leading global diversified professional service and investment management company. All of the foregoing are listed on the TSX. Ms. Gavan is also on the Patron's Council for Community Living Toronto.

Glenn A. McNamara

Mr. McNamara is a Professional Engineer with more than forty years of oil and gas exploration and production experience in progressively more senior roles in Canada and across a variety of international regions, including South America, the United States, Europe and Asia Pacific. His extensive commercial and operational experience spans both large organizations and smaller entrepreneurial environments, most recently serving as President & Chief Executive Officer and a director of Heritage Royalty Resource Corp. Prior to, Mr. McNamara's experience included serving as President of BG Canada, responsible for all aspects of BG Canada's business and holding several senior executive positions with ExxonMobil, ExxonMobil Canada, and Mobil Oil Canada, including President of ExxonMobil Canada West. Mr. McNamara is also a director of Whitecap Resources Inc. and Parex Resources Inc., both of which are listed on the TSX and Atlas Energy Corp., which is listed on the TSXV.

Sheldon B. Steeves

Mr. Steeves' principal occupation is as a Corporate Director. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a private junior oil and natural gas company, and spent over 15 years at Renaissance Energy Ltd., a Canadian oil and gas exploration company, where he was appointed Chief Operating Officer & Executive Vice-President in 1997. Mr. Steeves holds a Bachelor of Science degree in Geology from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Andrew M. Phillips

Mr. Phillips is the President and Chief Executive Officer of the Company and has over 25 years of experience in the oil and natural gas industry in the areas of exploration, geology, business development, asset evaluation and executive management. Prior to his appointment as President and Chief Executive Officer of the Company, Mr. Phillips was the President and Chief Executive Officer and a director of Home Quarter Resources Ltd. (Home Quarter), a private oil and natural gas company founded by Mr. Phillips in 2010 with producing properties and royalty interests in southwest Saskatchewan and Alberta. Home Quarter was successfully divested to a public oil and natural gas company in 2014. Prior thereto, Mr. Phillips was the Vice-President, Exploration at Evolve Exploration Ltd., a private junior oil and natural gas company with assets in Western Canada, and an exploration geologist at each of Profico Energy Management Ltd. and Renaissance Energy Ltd., both of which were Canadian oil and natural gas exploration companies. Mr. Phillips holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Petroleum Geologists. Mr. Phillips is a member of the Board of Directors of the Alberta Children's Hospital Foundation.

Pamela P. Kazeil

Ms. Kazeil is the Senior Vice-President, Finance & Chief Financial Officer of the Company, and has significant experience in the oil and natural gas industry managing finance, accounting, treasury, human resources, sustainability, tax and risk management. Prior to joining the Company, Ms. Kazeil held the Chief Financial Officer position at Sinopec Canada. Ms. Kazeil's experience includes serving as Vice-President, Finance of Daylight Energy Ltd. from 2008 to 2011, and prior thereto Ms. Kazeil held increasingly senior finance roles with Sword Energy Ltd. and its predecessor Thunder Energy Trust from 2004 to 2008, including as Vice-President, Finance and Chief Financial Officer. Ms. Kazeil started her accounting career at KPMG LLP in 2001. Ms. Kazeil is a Chartered Professional Accountant, a Fundamentals of Sustainability Accounting (FSA) Credential Holder and holds a Bachelor of Commerce degree from the University of Ottawa and a Bachelor of Education degree from the University of Saskatchewan. Ms. Kazeil is a member of the University of Calgary’s Audit Committee.

Daniel J. Bertram

Mr. Bertram is the Vice-President, Business Development & Chief Commercial Officer of the Company. Prior thereto, Mr. Bertram was the Senior Vice-President and Chief Strategy Officer at Superior Plus Corp., a leading North American energy distributor. From 2019 to 2023, Mr. Bertram was the Vice-President, Business Development at Certarus Ltd. and previously spent over five years at Alaris Royalty Corp. as Vice-President, Business Development, leading their origination and deployment efforts. Earlier in his career, he worked for Deans Knight Capital Management as an Investment Analyst and spent time in the investment banking industry. Mr. Bertram graduated in finance from Boston College and holds a CFA designation. Mr. Bertram is a member of the Board of the Edge School Athletes Society.

Michael T. Murphy

Mr. Murphy is the Vice-President, Geosciences and Capital Markets of the Company and over 20 years of experience across the oil and natural gas industry and related capital markets. Prior to joining the Company in January 2024, Mr. Murphy spent 10 years in sell side equity research focused on the energy sector. Most recently, he was an Analyst as part of a top-ranked equity research team at BMO Capital Markets, covering Canadian small/mid-cap exploration and production and royalty companies. Prior thereto, Mr. Murphy was a Senior Research Associate at Macquarie Capital Markets Canada. Mr. Murphy started his career as a geologist at multiple junior public oil and gas companies in roles of increasing responsibility, focused on both the Western Canadian Sedimentary Basin and international exploration and production. Mr. Murphy holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta.

CORPORATE CEASE TRADE ORDERS OR BANKRUPTCIES

During the past ten years, none of the current directors and executive officers of PrairieSky is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, 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. Other than disclosed below, none of the directors or executive officers of PrairieSky is as at the date of this AIF, or has been within ten years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Ms. Margaret McKenzie, who is a director of the Company, was a director of Endurance Energy Ltd. (Endurance), a corporation engaged in the exploration and production of natural gas. Endurance filed for creditor protection under the *Companies Creditors' Arrangement Act* on May 30, 2016. Ms. McKenzie resigned as a director of Endurance on March 31, 2016.

PERSONAL BANKRUPTCIES

None of the directors or executive officers of PrairieSky nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company has, within the past ten years, 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 proposed director.

PENALTIES OR SANCTIONS

No director, executive officer or promoter of PrairieSky, nor any shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court, securities regulatory authority or other regular authority or has entered into a settlement agreement with a securities regulatory authority.

Audit Committee

AUDIT COMMITTEE

The full text of the Audit Committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

PrairieSky's Audit Committee consists of Ms. Alderson (Chair), Mr. Duggal and Ms. Gavan. All members of the Audit Committee are independent and financially literate as those terms are used under National Instrument 52-110 - *Audit Committees*. See "*Directors and Executive Officers – Board of Directors of PrairieSky*".

Comprehensive Audit Quality Review

The Audit Committee is responsible for recommending the appointment of the external auditors, overseeing and monitoring their qualifications, independence and performance, and assessing the appropriateness of the audit fees. The Audit Committee continually assesses the Company's external auditors. On an annual basis, the Audit Committee reviews audit and non-audit fees, audit quality, independence, tenure of the auditors, and the controls and processes that help ensure the auditor's independence. Every five years, the Audit Committee performs a comprehensive audit quality review which is a broader and more in-depth review. The most recent comprehensive audit quality review was finalized in February 2024 and is further described below.

The Audit Committee completed its comprehensive audit quality review to assess audit quality and independence standards as required by the Committee's mandate for the five years ended December 31, 2023. The comprehensive review was led by the Chair of the Audit Committee with discussion and review by the full Audit Committee. The Audit Committee engaged an external advisor to collect data, conduct interviews and summarize findings in connection with the comprehensive review. The review was prepared in accordance with guidance published by Chartered Professional Accountants Canada, the Institute of Corporate Directors and the Canadian Public Accountability Board. This comprehensive review focused on the following three key factors of audit quality: 1) independence, objectivity and professional skepticism of the auditor; 2) quality of the engagement team and the audit firm; and 3) quality of communications and interaction with the auditor. This review included input from management and the Audit Committee in the form of a series of questions and answers and input from the external auditor, KPMG LLP, in the form of a questionnaire, an analysis of services provided and reports issued over the five-year period, and a series of audit quality indicators that were selected for measurement and review. The documents and data collected were linked to an Audit Quality Indicators Framework to facilitate the Audit Committee's review and discussion. A consideration of the comprehensive review was to address the possible risk of institutional familiarity resulting from KPMG LLP serving as the external auditor of PrairieSky since 2014. Regulatory requirements in Canada continue to be audit partner rotation every seven years with a five-year cooling off period. Following the initial appointment of KPMG LLP in 2014, partner rotation has occurred in 2019 and 2023, well within the Canadian regulatory requirements. The Audit Committee also reviewed the amount of non-audit related fees as a percentage of total fees paid to KPMG LLP over the five-year period ended December 31, 2023. The only non-audit related services provided by KPMG LLP during the five-year period related to tax services. On an annual basis, non-audit related fees were de minimis, totaling between 1% and 4% per year of total fees paid to KPMG LLP. Based on this review, the Audit Committee was satisfied that non-audit related fees would not impair KPMG's independence.

The comprehensive review concluded in February 2024, and based on the results of the review, the Audit Committee determined that it was satisfied with the audit quality provided by KPMG LLP and that after considering the regulatory requirements for partner rotations and other independence measures, retaining KPMG LLP is in the best interests of PrairieSky. Following the results of the Audit Committee's annual evaluation of KPMG LLP's independence and performance as the Company's external auditors, the Audit Committee and the Board believe that re-appointing KPMG LLP is in the best interests of the Company. As a result, at the next annual general meeting of the Company, the Board of Directors intends to recommend the reappointment of KPMG LLP, Chartered Professional Accountants, as external auditors of the Company.

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services which are outlined in the Audit Committee mandate in Appendix C to this AIF. The policies and procedures require pre-approval of all non-audit services, including estimated fees, by the Audit Committee or in certain circumstances, the chair or a subcommittee of the Audit Committee. The policies and procedures permit an overrun of no greater than 10% of the fee estimate. The Audit Committee, the chair or a subcommittee of the Audit Committee, as applicable, must pre-approve any costs that exceed such overrun. All audit and non-audit services are reported to the Audit Committee quarterly.

External Auditor Service Fees

	Year Ended December 31 2025	Year Ended December 31 2024
Audit Fees[1]	261,488	280,303
Audit-related Fees[2]	-	-
Tax Fees[3]	6,325	8,988
All Other Fees[4]	64,200	-
Total	332,013	289,291

Notes:

(1) Audit fees consist of aggregate fees paid during the respective year related to the audit of PrairieSky's annual financial statements, reviews of interim consolidated financial statements for the quarters of 2024 and 2025 fiscal years, or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of aggregate fees paid for assurance and related services that are reasonably related to the performance of the audit or review of PrairieSky's financial statements and are not reported as Audit Fees.

(3) Aggregate fees paid related to tax services.

(4) Aggregate fees paid for limited assurance for select ESG metrics disclosed in PrairieSky's 2024 Sustainability Report, which fees are excluded from the services reported under Audit Fees, Audit-Related Fees and Tax Fees.

Conflicts of Interest

Certain of the directors and executive officers of the Company are engaged in, and may continue to be engaged in, other activities in the industries in which the Company operates from time to time. At each Board meeting, the directors are asked to disclose any potential material conflicts of interest. The ABCA and Company policies provide that in the event that an officer or director 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 material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

Legal Proceedings and Regulatory Actions

As at the date hereof, there are no legal proceedings that PrairieSky is a party to, or that any of PrairieSky's property is the subject of, that is material to PrairieSky, and there are no such material legal proceedings known to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" to PrairieSky if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of PrairieSky's consolidated current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

Interest of Management and Others in Material Transactions

There were no: (i) penalties or sanctions imposed against PrairieSky by a court relating to securities legislation or by a security regulatory authority during its most recently completed financial year or during the current financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against PrairieSky that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements PrairieSky entered into before a court relating to securities legislation or with a securities regulatory authority during PrairieSky's most recently completed financial year or during the current financial year.

There were no material interests, direct or indirect, of any directors or executive officers of PrairieSky, any shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Company.

Transfer Agent and Registrar

Odyssey Trust Company at its principal offices in Calgary, Alberta acts as the transfer agent and registrar for the Common Shares.

Material Contracts

Except for contracts entered into in the ordinary course of business and those discussed in this AIF, the Company did not enter into any material contracts within the most recently completed financial year, or before the most recently completed financial year but which are still in effect.

Interests of Experts

NAMES OF EXPERTS

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to, the Company's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are KPMG LLP, the Company's independent external auditors, and GLJ, the Company's independent qualified reserves evaluator.

INTERESTS OF EXPERTS

KPMG LLP is the external auditor of the Company and is independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

As at the date hereof, the designated professionals (as defined in NI 51-102), beneficially owns, directly or indirectly, less than 1% of the Company's Common Shares.

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

Additional Financial and Other Information

The information contained in this AIF is as of December 31, 2025, unless otherwise indicated. Additional information about the Company may be available on the Company's website at www.prairiesky.com or on SEDAR+ at www.sedarplus.ca. Additional financial information is provided in PrairieSky's audited annual consolidated financial statements for the period ended December 31, 2025, and the accompanying management's discussion and analysis. Information about remuneration of directors and officers of PrairieSky, principal holders of the Common Shares and securities authorized for issuance under security-based compensation of the Company, will be contained in the Company's management information circular and proxy statement relating to the 2026 Annual General Meeting. In addition, the Company generally maintains supporting materials on its website which may assist in reviewing this AIF, including the Company's 2024 Sustainability Report (which contains a discussion of ESG issues).

For copies of the Company's financial statements and accompanying management's discussion and analysis, management information circulars and proxy statements, and additional copies of this AIF (in certain circumstances reasonable fees may apply), please contact:

Investor Relations
PrairieSky Royalty Ltd.
Suite 1700, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9
Telephone: 587.293.4000
Fax: 587.293.4001

Appendix A

FORM-51-101F2

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

FORM 51-101F2

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of PrairieSky Royalty Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2025, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2025	Canada	-	1,841,315	-	**1,841,315**

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, January 22, 2026

/s/ "Chad P. Lemke"

____

Chad P. Lemke, P. Eng.
Executive Vice President & CCO

Appendix B

Form 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of PrairieSky Royalty Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix A of this Annual Information Form.

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

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

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

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

The Reserves Committee of the Board of Directors of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

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

(b) the filing of the Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(signed) *"Andrew Phillips"*
Andrew Phillips
President & Chief Executive Officer

(signed) "*Pamela Kazeil*"
Pamela Kazeil
Senior Vice-President, Finance & Chief Financial Officer

(signed) "*Sheldon Steeves*"
Sheldon Steeves
Director, Chair of the Reserves Committee

(signed) "*Glenn McNamara*"
Glenn McNamara
Director, Member of the Reserves Committee

DATED as of this 9th day of February 2026.

Appendix C

Audit Committee Mandate

Effective: April 11, 2014, amended and restated October 20, 2025

Introduction

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of PrairieSky Royalty Ltd. (the "Company"). Its primary duties and responsibilities are to: review management's identification of principal financial risks and monitor the process to manage such risks; oversee and monitor the integrity of the Company's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance; oversee audits of the Company's financial statements; oversee and monitor the qualifications, independence and performance of the Company's external auditors; provide an avenue of communication among the external auditors, management and the Board; and report to the Board regularly.

Composition of Committee

The Committee shall consist of not less than three directors as determined by the Board, all of whom shall qualify as independent directors within the meaning attributed to such term in National Instrument 52-110 - Audit Committees (as implemented by the Canadian Securities Administrators and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, within the meaning attributed to such term in NI 52-110, and at least one member shall have accounting or related financial management expertise as the Board interprets such qualification in its business judgment.

Committee members may not, other than in their capacities as members of the Committee, the Board or any other committee of the Board, as applicable, accept directly or indirectly any consulting, advisory or other compensatory fee from the Company or any subsidiary of the Company, or be an "affiliated entity" (within the meaning attributed to such term in NI 52-110) of the Company or any subsidiary of the Company. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company that are not contingent on continued service should be the only compensation a Committee member receives from the Company.

Committee members will include only duly elected directors of the Company. At the request of the Committee, certain members of the Company's senior management and others may attend Committee meetings on an ad hoc or a regular basis, as required.

Appointment of Committee Members

Members of the Committee shall be appointed or continued as necessary at a meeting of the Board, provided that any member may be removed or replaced at any time by the Board and shall in any event cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

Chair

The Board shall appoint the Chair of the Committee (the "Chair"). If the Chair is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member of the Committee to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen by a majority of members of the Committee present at such meeting to preside over the meeting. The items pertaining to the Chair should be read in conjunction with the "Committee Chair" section of the Chair of Board of Directors and Committee Chair General Guidelines.

Committee Meetings

The Committee shall meet at least quarterly. The Chair may call additional meetings as required. In addition, a meeting may be called by the Board Chair, the President & Chief Executive Officer, any member of the Committee or the external auditors.

Committee meetings may be held in person, by means of electronic, telephone or other communication facilities as to permit all persons participating in the meeting to hear each other or by combination of any of the foregoing.

At all meetings of the Committee every question will be decided by a majority of the votes cast on the question. In case of an equality of votes, the Chair presiding at any meeting shall not be entitled to a second or casting vote.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Company.

A Committee member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a Committee meeting shall constitute waiver of notice of the meeting except where a member of the Committee attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by electronic, telephone or other communication facilities or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Attendance at Meetings

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee. The Committee may, by specific invitation, have other resource persons in attendance.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Chair or by a majority of the members of the Committee.

The Committee shall meet "in-camera" with the external auditors at least quarterly (in connection with the preparation of the annual and quarterly financial statements), and at such other times as the external auditors and the Committee consider appropriate.

The Senior Vice-President, Finance & Chief Financial Officer or any other person holding a similar role in accounting, risk, compliance and/or audit are expected to be available to attend the Committee's meetings or portions thereof, unless otherwise excused from all or part of any such meeting by the Chair.

Minutes

The Committee shall appoint a secretary who need not be a member of the Committee. The secretary shall keep minutes of the meetings of the Committee. Minutes of Committee meetings shall be sent to all Committee members and the external auditors. The full Board shall be kept informed of the Committee's activities by a report following each Committee meeting, unless each Board member who is not a member of the Committee is in attendance at such Committee meeting.

Specific Responsibilities

A. Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Company's annual information form or other public disclosure documentation.

B. Annual Financial Statements

1. Discuss and review with management and the external auditors, the Company's annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

   (a) The annual audited financial statements, including accounting policies and significant management estimates and judgments, and/or any significant changes in the Company's selection or application of accounting principles, and any major issues as to the adequacy of the Company's internal controls and disclosure controls and procedures;

   (b) Management's Discussion and Analysis;

   (c) A review of the external auditors' audit examination of the financial statements and their report thereon;

   (d) Review of any significant changes required in the external auditors' audit plan;

   (e) A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information; and

   (f) A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards or in accordance with regulatory requirements.

2. Following completion of the matters contemplated above and review of consistency of disclosure, recommend approval to the Board of the Company's:

   (a) Year-end audited financial statements; and

   (b) Management's Discussion and Analysis, including non-GAAP and other financial measures.

C. Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for their filing or distribution) or formally recommend for approval to the Board, the Company's:

(a) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis; and

(b) Any significant changes to the Company's accounting policies, significant management statements and judgments.

D. Other Financial Filings and Public Documents

4. The Committee is to review prospectuses, annual information forms (AIF), business acquisition reports (BARs) and all other public disclosure containing audited or unaudited financial information before release and prior to Board approval.

5. Review and discuss with management financial information, including annual and interim earnings press releases, the use of "pro forma" or non-GAAP financial information and guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies). Consideration should be given as to whether the information is consistent with the information contained in the financial statements of the Company. Such review and discussion should occur before public disclosure and may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Committee must be satisfied that adequate procedures are in place for the review of the Company's disclosure of all other financial information and shall periodically assess the reasonableness of those procedures.

E. Internal Control Environment

6. Ensure that management provides to the Committee an annual report on the Company's control environment as it pertains to the Company's financial reporting process and controls.

7. Ensure that management reports to the Committee at least quarterly on compliance with legal, ethical and regulatory requirements.

8. Review management's process for the certification of annual and interim financial reports in accordance with required securities legislation.

9. Review with the President & Chief Executive Officer, the Senior Vice-President, Finance & Chief Financial Officer and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Company's internal controls and procedures for financial reporting which could adversely affect the Company's ability to record, process, summarize and report financial information required to be disclosed by the Company in the reports that it files or submits under applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Company or other employees who have a significant role in the Company's internal controls and procedures for financial reporting.

10. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Company.

11. Review management's processes in place to prevent and detect fraud.

12. Review the audit plans of the external auditors, and if applicable, the internal auditors, and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud or other illegal acts. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

F. *Other Review Items*

13. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets.

14. Review all related party transactions between the Company and any officers or directors, including affiliations of any officers or directors as the Committee considers appropriate.

15. Review legal and regulatory matters, including correspondence and filings with regulators and governmental agencies, which may have a material impact on the interim or annual financial statements, related corporate compliance policies, and programs and reports received from regulators or governmental agencies, including but not limited to reporting documents filed under the *Extractive Sector Transparency Measures Act* and the *Fighting Against Forced Labour and Child Labour in Supply Chains Act*.

16. Review policies and practices with respect to risk management, including trading and hedging activities and insurance.

17. Review policies and practices with respect to cyber-security risk management, including but not limited to: (a) assessing best practices from industry associations and recognized information security organizations in relation to the Company's business and operations; and (b) reviewing third party vulnerability and security tests and assessments performed by or on behalf of the Company.

18. In conjunction with the Corporate Governance Committee, review procedures for the receipt, retention and treatment of complaints received by the Company, regarding accounting, internal accounting controls, or auditing matters including confidential, anonymous submissions by employees of the Company, regarding accounting, internal accounting controls, or auditing matters.

19. Review ESG-related disclosures and external assurance of ESG information and assess the effectiveness of related internal controls.

20. Meet on a periodic basis separately without management.

External Auditors

21. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, reviews or attest services for the Company. The external auditors shall report directly to the Committee.

22. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chair or by a majority of the members of the Committee.

23. Obtain and review a report from the external auditors at least annually regarding:

    (a) The external auditors' internal quality-control procedures;

    (b) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues; and

(c) Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Company and its affiliates in order to determine the external auditors' independence.

24. Review and evaluate:

(a) The external auditors' performance and the lead partner of the external auditors' team's performance, and make a recommendation to the Board regarding the reappointment of the external auditors at the annual meeting of the Company's shareholders or regarding the discharge of such external auditors and the subsequent appointment of a new external auditor;

(b) The terms of engagement of the external auditors together with their proposed fees;

(c) External audit plans and results; and

(d) Any other related audit engagement matters.

25. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

26. Perform a comprehensive audit quality review to assess audit quality and independence standards every five years in accordance with the guidance published by Chartered Professional Accountants Canada, the Institute of Corporate Directors and the Canadian Public Accountability Board.

27. Consider and review with the external auditors and management:

(a) Significant findings during the year and management's responses and follow-up thereto;

(b) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response;

(c) Any significant disagreements between the external auditors and management; and

(d) Any changes required in the planned scope of their audit plan.

H. Pre-Approval of Audit and Non-Audit Services

28. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) for the Company and/or any subsidiaries in advance of the provision of those services by the external auditors (subject to de minimis exceptions for non-audit services described in NI 52-110, the rules and forms under applicable Canadian federal and provincial legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

29. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

30. Delegate, if the Committee deems necessary or desirable, to the Chair or a subcommittee consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 28 and 29. The decision of the Chair or any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

31. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 28 and 29, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under applicable Canadian federal and provincial legislation and regulations to management.

32. The Committee shall evidence their pre-approval for services to be provided by the external auditors as follows: (a) in situations where the Chair or a subcommittee pre approves work under the delegation of authority described in paragraph 30, the Chair or a member of the subcommittee, as applicable, will provide email confirmation of approval of the engagement to the external auditors and the other members of the Committee; and (b) in all other situations, a resolution described in paragraph 30 of the Committee shall be required and confirmation of approval shall be communicated to the external auditors by email.

33. All audit and non-audit services to be provided by the external auditors shall be provided pursuant to an engagement letter that shall: (a) be in writing and signed by the external auditors; (b) specify the particular services to be provided; (c) specify the period in which the services will be performed; (d) specify the estimated total fees to be paid, which, at the conclusion of the service, shall not exceed the estimated total fees pre-approved by the Committee or the Chair or a subcommittee, as applicable, by more than 10%; and (e) include a confirmation by the external auditor that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian generally accepted accounting standards.

    For clarity, the Committee pre approval process permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate, and, if required, further Committee, Chair or subcommittee, as applicable, approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Committee, Chair or subcommittee, as applicable, must be notified and an additional pre approval obtained prior to the engagement continuing.

Miscellaneous

34. Review and concur in the appointment, replacement, reassignment, or dismissal of the Senior Vice-President, Finance & Chief Financial Officer.

35. Report Committee actions to the Board with such recommendations, as the Committee may deem appropriate.

36. Conduct or authorize any review or investigation into any matters within the Committee's scope of responsibilities. The Committee shall have unrestricted access to personnel and information and any resources necessary to carry out its responsibility. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and in carrying out of its duties. The Committee shall have the authority to set and pay compensation for any such advisors.

37. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

38. Perform such other functions as required by law, the Company's articles or by-laws, or the Board.

39. Consider any other matters referred to it by the Board.

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.