ANNUAL INFORMATION FORM

For the Year Ended December 31, 2022

Dated March 28, 2023

CARDINAL ENERGY LTD.

www.cardinalenergy.ca

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GLOSSARY

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board or **Board of Directors** means our board of directors.

Cardinal, we, us or **our** means Cardinal Energy Ltd.

Venturion means Venturion Oil Corp.

Reserves

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.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Ltd., independent petroleum consultants of Calgary, Alberta.

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

Report means the report prepared by GLJ dated February 27, 2023, evaluating 100% of our crude oil, natural gas and natural gas liquids reserves as at December 31, 2022.

Securities and Other Terms

5.50% Debentures means our 5.50% extendible convertible unsecured subordinated debentures which were due December 31, 2020.

8.00% Debentures means our 8.00% convertible unsecured subordinated debentures which were due December 31, 2022.

2020 Secured Notes means our second lien secured notes which were issued on December 30, 2020, as more particularly described under the heading "*General Development of Our Business – History and Development – Developments in 2020*".

2020 Warrants means our common share purchase warrants which were issued on December 30, 2020, each of which entitled the holder to acquire one Common Share at an exercise price of $0.55 for the period commencing on June 30, 2021 to December 30, 2023.

2021 Secured Notes means our second lien secured notes which were issued on July 14, 2021, as more particularly described under the heading "*General Development of Our Business – History and Development – Developments in 2021*".

2021 Warrants means our common share purchase warrants which were issued on July 14, 2021, each of which entitled the holder to acquire one Common Share at an exercise price of $3.16 for the period commencing on December 14, 2021 to July 14, 2024.

Common Shares means our common shares as presently constituted.

Credit Facility means our $155 million syndicated credit facility, as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Debentureholders means the holders of 5.50% Debentures or the 8.00% Debentures, as applicable.

Shareholders mean the holders of Common Shares from time to time.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	MMbtu	million British Thermal Units
NGLs	natural gas liquids		

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
ARO	abandonment and reclamation obligations
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
CO_2	carbon dioxide
EOR	enhanced oil recovery
ESG	environmental, social and governance
GHG	greenhouse gas
m^3	cubic metres
MBoe	thousand barrels of oil equivalent
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s or M$	thousands of dollars
$MM	millions of dollars

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements, other than statements of historical fact, contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology.

In addition, there are forward looking statements in this Annual Information Form under the headings: "*General Development of Our Business*" as to our business plans, focus, strategies and objectives, production decline rates, and our 2023 capital budget; "*General Description of Our Business*" as to our business plans, focus, strategies and objectives, production decline rates, and our ESG plans and initiatives; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, royalties, operating costs, development costs, abandonment and reclamation costs, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow from operating activities, debt and equity issuances, our future abandonment and reclamation obligations; our 2023 capital program; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our drilling and development plans and opportunities, optimization and operating plans, decline rates, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- the future development potential of our assets;
- future well performance and related well economics;
- expectations regarding the renewal of our Credit Facility;
- projections of market prices and costs and exchange and inflation rates;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- future commodity prices;
- supply and demand for oil, natural gas and NGLs;
- expected royalty rates and the anticipated benefits of royalty incentive programs;
- treatment under governmental regulatory regimes and tax laws;
- impact of international events and agreements on Canadian producers;
- impact of federal and provincial legislative and regulatory changes on the oil and gas industry;
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on us; and
- our assessment of the impact of the various risks identified under the heading "*Risk Factors*".

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

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- impacts of pandemics;
- our ability to market our oil, natural gas and NGLs;
- market prices of oil, natural gas and NGLs;
- exploration, development and production risks;
- operational risks and liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- the uncertainties in regard to the timing of our exploration and development program;
- the occurrence of unexpected events;
- inflation and cost management;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- access to a skilled workforce;
- water and CO_2 supplies;
- effects of inflation;
- stock market volatility;
- risks relating to our Credit Facility;
- restrictions on our ability to pay dividends and the impact of changes to our dividend policy;
- political or economic developments;
- changes in general economic, market and business conditions;
- the impact of negative public and investor sentiment;
- incorrect assessments of the value of acquisitions;
- risks associated with various projects;
- operational dependence on others and third party risks;
- the impact of our risk management activities;

- ability to obtain regulatory and other third party approvals;
- uncertainties and changes in royalty regimes and other regulatory changes;
- environmental and climate change risks;
- fluctuations in foreign exchange or interest rates;
- the inability to access capital from internal and external sources;
- fluctuations in the availability and costs of borrowing;
- our title to and rights to produce from our assets;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- the availability and cost of insurance;
- costs of new technologies;
- fluctuation in the supply and demand for oil and natural gas;
- future dilution;
- management of growth;
- expiration of leases or licences;
- the results of litigation or regulatory proceedings that may be brought against us;
- uncertainty regarding the impact of legal developments pertaining to Indigenous rights and treaty claims;
- impacts of the Russian Ukrainian conflict and related actions;
- changes in income tax laws or changes in tax laws, including carbon taxes, and incentive programs relating to the oil and gas industry;
- seasonality;
- exposure to third party credit risks;
- potential conflicts;
- information technology and cyber-security issues;
- risks associated with expanded activities;
- fluid disposal;
- potential opposition from non-governmental organizations;
- reputational risks associated with our operations; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; differentials; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating and other costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

OIL AND GAS ADVISORY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (6 Mcf: 1 Bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this document and in other materials disclosed by us, we adhere to International Accounting Standards Board's most current International Financial Reporting Standards ("**IFRS**" or "**GAAP**"), however we also employ certain non-GAAP and other financial measures to analyze financial performance, financial position, and cash flow including, but not limited to "netbacks". These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures used herein should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as earnings (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators our performance. The most directly comparable GAAP measure for netback is gross sales price. Refer to the section entitled "Non-IFRS and Other Financial Measures" contained within our MD&A for the year ended December 31, 2022, available on SEDAR at www.sedar.com, for additional disclosures relating to these non-GAAP measures, which information is incorporated in this Annual Information Form by reference.

CARDINAL ENERGY LTD.

We were incorporated under the *Business Corporations Act* (Alberta) as 1577088 Alberta Ltd. on December 21, 2010. On May 25, 2012, we changed our name to "Cardinal Energy Ltd.". On June 28, 2012, we amended our Articles to change the rights, privileges, restrictions and conditions in respect of our Common Shares, including enabling us to issue stock dividends declared on our Common Shares. On July 27, 2012, we amended our Articles to remove our private company restrictions. On September 9, 2013, we amended our Articles to consolidate our Common Shares on a three for one basis and to amend the percentage of the average market price used when calculating a stock dividend on our Common Shares. See "*Description of our Capital Structure – Share Capital – Common Shares*".

During the year ended December 31, 2015 we completed a number of vertical amalgamations with our then wholly owned subsidiaries and on January 1, 2022, Venturion was amalgamated into us. We currently do not have any subsidiaries.

Our head office is located at Suite 600, 400 – 3rd Avenue SW, Calgary, Alberta T2P 4H2 and our registered office is located at Suite 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

We are a low decline, oil focused company that produces in four core areas in Western Canada. We have a balanced portfolio, deep development drilling inventory and defined ESG focus. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We commenced operations in May of 2012 and on December 17, 2013, we completed an acquisition of assets located in Southeast Alberta, closed our initial public offering and our Common Shares commenced trading on the Toronto Stock Exchange. The following is a summary of the development of our business over the last three years.

Developments in 2020

In March 2020, weakness in commodity prices and reduced global economic activity following the outbreak of the novel coronavirus ("**COVID-19**") caused us to reduce our 2020 capital budget to approximately $31 million and indefinitely suspend our dividend, effective March 2020, in order to preserve our balance sheet. We undertook a variety of further initiatives in 2020 in response to COVID-19 and low commodity prices including: shutting-in approximately 20% to 25% of our higher operating cost production allowing us to retain the long-term value of our reserves; reduced our Board, executive, office and field staff salaries and retainers by 20%; ceased our corporate bonus program; reduced our corporate savings plan contributions; negotiated various cost reductions with key service providers; and accessed various government subsidies and ARO funding.

Our $325 million Credit Facility was available on a revolving basis until May 23, 2020. While renewal negotiations were ongoing, we signed numerous extensions to the revolving period and borrowing base determination date of our Credit Facility from May to December, 2020 and on December 9, 2020, our Credit Facility was renewed at $225 million and the revolving period and maturity date were extended to May 31, 2021 and May 31, 2022, respectively.

On June 19, 2020, we received Debentureholder approval for certain amendments to our 5.50% Debentures that were maturing December 31, 2020. As a result, all Debentureholders had the right to exchange their 5.50% Debentures for the 8.00% Debentures. On August 5, 2020, $28.2 million principal amount of the 5.50% Debentures were exchanged for an equal aggregate principal amount of 8.00% Debenture which, among other things, had a higher interest rate, a conversion price of $1.25 per Common Share and a maturity date of December 31, 2022.

On December 30, 2020, we completed a private placement of approximately $16.9 million principal amount of second lien secured notes (the "**2020 Secured Notes**") which were issued at a 4% discount for net proceeds of $16.2 million. The 2020 Secured Notes bore interest at 12% per annum, with interest accrued semi-annually and added to the principal amount outstanding and payable on maturity. The 2020 Secured Notes had a maturity date of June 30, 2022, and contained an extension provision, exercisable by either us or the holders thereof on 30 days' prior written notice, to extend the maturity date to November 30, 2022. The 2020 Secured Notes also had a second lien on all of our assets and included debt incurrence restrictions.

As part of the private placement, each subscriber was also required to subscribe for a pro rata number of units totaling 8,122,000 units, at a subscription price of $0.50 per unit for net proceeds of $4.0 million. Each unit consisted of one Common Share and one 2020 Warrant. The proceeds from the private placement were used to fund the repayment of the 5.50% Debentures which were maturing on December 31, 2020 and for general corporate purposes. It was a condition to the financing that insiders participate in the private placement. As a result, certain of our directors subscribed for approximately $3.9 million principal amount of the 2020 Secured Notes and 1,875,000 units. Further particulars regarding insider participation in the private placement are set forth in our material change report dated December 15, 2020, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Developments in 2021

On January 15, 2021, we announced that we had set a 2021 capital budget of $25 to $30 million focused on workovers and a well reactivation program. The 2021 budget did not contemplate drilling any new wells although we also announced that we would revisit a potential drilling program in the second half of 2021 depending on commodity price levels.

On February 4, 2021, we issued a notice of redemption to the holders of the outstanding 8.00% Debentures to redeem, as of March 11, 2021 (the "**Redemption Date"**), all of the aggregate principal amount of the 8.00% Debentures for cash. In accordance with their terms, holders of the 8.00% Debentures had the right to convert their 8.00% Debentures, at their option, into Common Shares at a conversion price of $1.25 per Common Share at any time prior to 5:00 p.m. (Toronto time) on March 10, 2021. A holder electing to convert the principal amount of their

8.00% Debentures was entitled to receive approximately 800 Common Shares per $1,000 principal amount of 8.00% Debentures converted plus a cash payment for accrued unpaid interest up to, but excluding, the date of conversion (less any tax required to be deducted). Prior to the Redemption Date, $28.0 million of principal amount of the 8.00% Debentures representing approximately 99.3% of the outstanding 8.00% Debentures was voluntarily converted into an aggregate of 22,410,000 Common Shares. The redemption of the remaining $0.2 million principal amount of the 8.00% Debentures was funded through our Credit Facility.

Effective May 12, 2021, we amended our Credit Facility to extend the revolving date and maturity date to May 31, 2022 and May 31, 2023, respectively.

On May 13, 2021, we announced that our Board of Directors had approved an increase in our 2021 capital budget to $46 million.

On June 1, 2021, we announced that we had entered into an arrangement agreement to acquire Venturion, a privately held company (the "**Venturion Acquisition**") for a purchase price of approximately $47.5 million after deducting maximum hedging losses of $2.5 million and subject to post-closing adjustments. The consideration was to consist of approximately 6.3 million Common Shares and approximately $27.9 million of cash which was to be firstly utilized to repay Venturion's outstanding net debt at closing (including closing costs) estimated to be approximately $10.9 million and with the balance to be paid to the Venturion shareholders. Venturion's assets consisted of approximately 2,400 Boe/d of production (approximately 650 bbl/d light and medium crude oil, 1,350 bbl/d heavy oil, 20 bbl/d liquids and 2.3 mmcf/d conventional natural gas) focused in central Alberta and other minor properties in British Columbia. The majority of the acquired assets were located in our Wainwright operating area.

In conjunction with the Venturion Acquisition, we also announced our intention to complete a private placement (the "**Note Financing**") of up to $12.5 million principal amount of subordinated second lien secured notes (the "**2021 Secured Notes**") which would bear interest at 10% per annum with an effective interest rate of 11.5%, with interest compounded and accrued semi-annually and added to the principal amount outstanding, payable on maturity. The 2021 Secured Notes had a maturity date of July 14, 2024 and had a second lien on all of our assets and included debt incurrence restrictions. As part of the Note Financing, we also agreed to issue one common share purchase warrant (the "**2021 Warrants**") for each $5.00 principal amount of 2021 Notes. Each 2021 Warrant entitled the holder to acquire one Common Share at an exercise price equal to the deemed price of the Common Shares being issued pursuant to the Venturion Acquisition ($3.16) for a period of 36 months from the issue date.

We completed the Note Financing on July 14, 2021 and the Venturion Acquisition on July 15, 2021. The Note Financing was fully funded by insiders. Further particulars regarding insider participation in the Note Financing is set forth in our material change report dated June 11, 2021, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

On January 1, 2022, Venturion was amalgamated into Cardinal.

On October 6, 2021, we closed the disposition of approximately 200 Boe/d (32 bbl/d light/medium oil, 28 bbl/d NGLs, 0.8 mmcf/d natural gas) of non-core gas weighted production and associated lands and liabilities for gross proceeds of $10.5 million.

On November 4, 2021, we announced that our Board of Directors had approved our 2022 capital budget of $70 to $80 million and an additional investment of $8 to $10 million for asset retirement obligations. The 2022 capital budget was designed to take advantage of our low corporate decline rate and focused on optimizing our long life asset base. The capital budget included the drilling and completion of 18 wells across our asset base and reactivated and optimized down production. We also planned to continue with our CO_2 injection program at Midale and by drilling two CO_2 injectors in 2022 to increase the amount of carbon we capture and continue to proactively upgrade our pipeline and facility infrastructure. As part of this budget, funds were also directed to increasing liquids recovery from our gas production as well as to continue our focus on ESG initiatives that provide economic returns including the reduction in direct emissions.

On November 25, 2021, we prepaid the 2020 Secured Notes for a payment of $19.2 million which included the principal amount, $1.9 million of accrued interest and a pre-payment fee of $0.4 million.

Developments in 2022

On March 14, 2022, we announced that our Board of Directors had approved an increase to our 2022 capital and ARO budget of $15 million which included approximately $5 million for strategic land acquisitions and $10 million for additional ARO expenditures.

On March 31, 2022, we prepaid the 2021 Secured Notes for a payment of $13.7 million which included the principal amount, $0.9 million of accrued interest and a pre-payment fee of $0.3 million.

Effective May 9, 2022, we renewed our Credit Facility with a syndicate of lenders. Consistent with our strategy of reducing our overall corporate debt levels and to reduce additional fees, we reduced the size of our Credit Facility from $225 million to $185 million. In the fourth quarter of 2022, the Company elected to further reduce our Credit Facility to $155 million to reduce standby fees. For further information on our Credit Facility, see "*Description of our Capital Structure – Credit Facility*".

We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve and on March 17, 2020, we suspended our dividend due to the economic environment. On May 12, 2022, we announced that our Board of Directors had approved the reinstatement of our monthly dividend starting at $0.05 per Common Share per month in June 2022.

On June 13, 2022, we announced that all outstanding 2020 Warrants and 2021 Warrants had been exercised. The proceeds were used to reduce our outstanding debt, further supporting our net debt reduction strategy. There are no remaining 2020 Warrants or 2021 Warrants outstanding.

On June 27, 2022, we announced that the Toronto Stock Exchange had accepted our intention to commence a normal course issuer bid ("**NCIB**"). Pursuant to the NCIB, we are permitted to purchase up to 12,319,686 Common Shares representing approximately 10% of our public float as of June 20, 2022 over a twelve month period commencing June 30, 2022. As at March 31, 2023, we had repurchased and cancelled 3,724,156 Common Shares at an average price of $7.05 per Common Share, for a total cost of $26.3 million.

On July 28, 2022, we announced that our Board of Directors had approved a $30 million increase to our 2022 capital budget to take advantage of opportunities and to account for inflationary pressures on our existing capital budget.

On September 12, 2022, we announced that our Board of Directors had approved an increase in our monthly dividend commencing in the fourth quarter of 2022 from $0.05 per Common Share to $0.06 per Common Share.

On September 15, 2022, we announced that we had been included in the Toronto Stock Exchange's 2022 TSX30™, a flagship program recognizing the 30 top performing TSX stocks over a three-year period based on dividend-adjusted share price appreciation. For the three years ended June 30, 2022, our share price increased by 222%.

On November 8, 2022, we announced that our Board of Directors had approved our 2023 capital budget of $97 million and an additional investment of $23 million for ARO. The 2023 capital budget takes advantage of our low corporate decline rate and focuses on optimizing our long life asset base. Drilling activity will be focused on continuing to develop and expand our Clearwater assets in northern Alberta, following up our successful Rex eight-leg multilateral at Wainwright, optimizing use of our new infrastructure at Tide Lake and pushing forward CO_2 EOR development at Midale.

Significant Acquisitions

We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

We are a Canadian company focused on low decline light and medium quality oil production in Western Canada. Our objective is to build core operating areas with sufficient scale of production as well as organic and acquisition growth prospects to achieve operational cost and production efficiency in each core area. We manage exploration, production and marketing risks through the expertise of our experienced technical and management personnel.

Specialized Skill and Knowledge

We employ individuals with various professional skills in the course of pursuing our business plan. In addition, specialized consultants are available to assist us in areas where we feel we don't need full-time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, we believe our management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows us to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is intensely competitive and we are required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more and more competitive and complex. We believe that we have a strong competitive position in the areas in which we operate, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We attempt to enhance our competitive position by operating in areas where we believe our technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. We believe that we will be able to explore for and develop new production and reserves with the objective of increasing our cash flow from operating activities and reserve base. See "*Risk Factors – Competition*", "*Risk Factors – Availability of Supplies for EOR Schemes*" and "*Risk Factors – Inflation and Cost Management*".

Cycles

Our business is generally not cyclical. However, our operational results and financial condition are dependent on prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years. Oil and natural gas prices are determined by a number of factors, including global and local supply and demand factors, egress options, weather, general economic conditions as well as conditions in other oil and natural gas producing and consuming regions. See "*Risk Factors – Prices, Markets and Marketing*".

In addition, the exploration for and the development of crude oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variations, including "freeze up" and "break up", affect access in certain circumstances. Consequently, during periods when weather which makes the ground unstable, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. See "*Risk Factors – Seasonality*".

Employees

As at December 31, 2022, we had 66 full-time employees located at our head office and 100 full-time employees located in the field.

Environmental, Health and Safety Policies

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on our earnings and our overall competitiveness. For a description of the financial and operational effects of environmental protection requirements on our capital expenditures, earnings and competitive position, see: "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors*".

We strive for an injury-free workplace for our employees and contractors, and we promote a safety culture through systems, processes and continued learning to mitigate risks. Safety is a core element across our organization and is kept top-of-mind in everything we do.

Our approach to maintaining safe and reliable operations starts with our executive team and is embodied by rigorous health and safety programs with ongoing process and occupational safety improvements. We continuously plan and practice effective responses to unlikely incidents, always prioritizing worker and community safety as well as environmental protection.

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

Our safety record is in the top tier of the industry as is our regulatory compliance approval level.

Our teams develop integrated emergency response preparedness plans between our Calgary staff, staff in our various operating areas, and in conjunction with local authorities, emergency services and local communities. These measures are in place to allow us to effectively respond to an environmental or safety-related incident, should it arise. These plans are reinforced with live exercises in the field and corporately. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of our operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist us in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks in our business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and safety audits.

We remain focused on creating, enhancing and delivering value to our Shareholders. One way we seek to protect value is by better understanding, disclosing and managing our environmental and social impacts. In recognition of the importance of clear Board oversight and risk management for ESG matters, we have established a separate ESG Committee of our Board.

We are also proud to have demonstrated our commitment to transparency and ethical practices in our 2021 ESG report. This report, available for viewing on our website, provides a comprehensive look at our ESG practices while highlighting the proactivity and excellent execution our employees have always demonstrated in advancement of our ESG performance. Key highlights of the report include our high safety performance, our current and future net zero emissions operations, our proactive asset integrity program and replacement of aging assets and our strong governance and community focus.

We continued our strong corporate emissions performance in 2022. Through our world class, Carbon Capture and Sequestration ("**CCS**") enhanced oil recovery ("**EOR**") operation at Midale, we sequestered approximately 292,000 tonnes of CO_2 in 2022. As in 2021, in 2022 two additional injection wells were drilled and brought online at Midale over the summer. These will expand and enhance our CO_2 sequestration, while supporting incremental oil recovery from the Midale Unit. To date, the Midale Unit has sequestered over five million tonnes of CO_2 and reduced oil production decline rates to approximately 3% to 5%.

Cardinal also implemented emissions reduction projects at 80 wellsites across Alberta, reducing vented greenhouse gas emissions by approximately 2,198 tonnes.

In 2022, Cardinal was an active participant in various government programs focused on well, facility and pipeline abandonment, as well as reclamation. During the year, Cardinal abandoned over 150 wells, 250 kilometers of pipeline and 9 facilities. We also reclaimed more than 100 well sites during the year and exceeded all regulatory requirements for spending allocations on inactive liabilities.

We further strengthened our relationships with the various First Nations living in and around our areas of operation, particularly in Slave Lake, a core area of our production. Through our operations, we have been exposed to the challenges of individuals living in remote areas and strongly believe that we, as a community partner, have a role to play.

The Slave Lake Homeless Coalition has a goal to provide services for those experiencing homelessness, with the long-term goal of implementing solutions for those individuals facing housing challenges. The first step has been to set up a temporary shelter program, with a goal of establishing a permanent facility in the near term. In recognition of Truth and Reconciliation Day, we pledged funds to assist in the initial development of the program. We have further committed to ongoing collaboration with the Slave Lake Homeless Coalition to develop a permanent solution to end homelessness in Slave Lake and the surrounding area.

We continue to execute projects to enhance our ESG performance and remain committed to making ESG a pillar of our business.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 27, 2023. The statement is effective as of December 31, 2022. Reserve evaluations have not been updated since the effective date and therefore do not reflect changes in our reserves since that date. The preparation date of the Statement of Reserves Data and Other Oil and Gas Information outlined below is March 28, 2023. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Appendices A and B, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2022 as contained in the Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present value of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged GLJ to provide an evaluation of 100% of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of our reserves are in Canada.

We determined the future net revenue and net present value of future net revenue after income taxes by utilizing the before income tax future net revenue from the Report and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of our value as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2022 should be consulted for additional information regarding our future income taxes.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs arising from the anticipated development and production of resources, net of associated royalties, operating costs, development costs and abandonment and reclamation costs. Abandonment and reclamation costs included in the Report are the costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned.

The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbls)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbls)	HEAVY CRUDE OIL Gross (Mbbls)	HEAVY CRUDE OIL Net (Mbbls)	CONVENTIONAL NATURAL GAS (1) Gross (MMcf)	CONVENTIONAL NATURAL GAS (1) Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbls)	NATURAL GAS LIQUIDS Net (Mbbls)
	SUMMARY OF OIL AND NATURAL GAS RESERVES AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS							
PROVED:								
Developed Producing	43,715	37,095	24,579	21,121	39,421	34,510	2,703	2,178
Developed Non-Producing	838	744	194	178	1,859	1,615	61	52
Undeveloped	4,650	3,995	1,178	1,123	1,795	1,659	191	172
TOTAL PROVED	49,203	41,834	25,951	22,421	43,075	37,785	2,955	2,401
TOTAL PROBABLE	16,027	13,401	7,976	6,685	16,324	14,090	1,019	852
TOTAL PROVED PLUS PROBABLE	65,230	55,236	33,927	29,106	59,399	51,874	3,974	3,253

Note:

(1) Includes solution gas.

RESERVES CATEGORY	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/ YEAR $/Boe (1)
	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2022 BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					
PROVED:						
Developed Producing	2,577	1,784	1,353	1,101	937	20.46
Developed Non-Producing (2)	(114)	(51)	(31)	(22)	(18)	(24.69)
Undeveloped	246	156	111	83	64	19.97
TOTAL PROVED	2,709	1,890	1,434	1,162	983	19.65
TOTAL PROBABLE	1,250	581	351	244	184	15.06
TOTAL PROVED PLUS PROBABLE	3,959	2,471	1,784	1,406	1,167	18.54

Notes:

(1) Based on net reserves.

(2) The costs to abandon and reclaim all inactive company interest wells, pipelines and facilities have been included in the proved developed non-producing and proved plus probable reserves categories. Those costs associated with active company working interest wells, pipelines and facilities have been included in the proved developed producing and proved plus probable reserves categories.

RESERVES CATEGORY	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2022 AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
PROVED:					
Developed Producing	2,193	1,580	1,227	1,015	876
Developed Non-Producing	(90)	(39)	(24)	(18)	(15)
Undeveloped	188	117	82	61	47
TOTAL PROVED	2,292	1,658	1,285	1,059	908
TOTAL PROBABLE	951	441	267	186	140
TOTAL PROVED PLUS PROBABLE	3,243	2,100	1,552	1,244	1,048

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2022
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE[1] ($MM)	ROYALTIES[2] ($MM)	OPERATING COSTS ($MM)	DEVELOP-MENT COSTS ($MM)	ABANDON-MENT AND RECLAMATI-ON COSTS [3] ($MM)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAX EXPENSES ($MM)	FUTURE INCOME TAX EXPENSES ($MM)	FUTURE NET REVENUE AFTER FUTURE INCOME TAX EXPENSES ($MM)
TOTAL PROVED	8,030	1,306	3,229	181	605	2,709	417	2,292
TOTAL PROVED PLUS PROBABLE	11,039	1,838	4,410	225	608	3,959	716	3,243

Notes:

(1) Total revenue includes company revenue before royalties and includes other income.

(2) Royalties include Crown, freehold and overriding royalties, freehold mineral tax and Saskatchewan Resource Surcharge.

(3) Represents abandonment and reclamation costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*".

PRODUCT TYPE	FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS FUTURE NET REVENUE BEFORE INCOME TAXES [1] (discounted at 10%/year) ($MM)	UNIT VALUE [2] ($/Boe)
TOTAL PROVED:		
Light and Medium Crude Oil [3]	1,007	21.49
Heavy Crude Oil [3]	405	17.34
Conventional Natural Gas [4]	21	7.77
	1,434	19.65
TOTAL PROVED PLUS PROBABLE		
Light and Medium Crude Oil [3]	1,248	20.09
Heavy Crude Oil [3]	511	16.74
Conventional Natural Gas [4]	25	7.03
	1,784	18.54

Notes:

(1) Other company revenue and costs not related to a specific product type have been allocated proportionately to product types listed.

(2) Unit values are based on net reserves.

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

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

Definitions and Notes to Reserves Data Tables

In the tables set forth above and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **gross** means:

    (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

    (b) in relation to wells, the total number of wells in which we have an interest; and

    (c) in relation to properties, the total area of properties in which we have an interest.

2. **net** means:

    (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

    (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

    (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

    Reserve Categories

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

    (a) analysis of drilling, geological, geophysical and engineering data;

    (b) the use of established technology; and

    (c) specified economic conditions (see the discussion of "economic assumptions" below).

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

    (a) 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.

    (b) 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.

4. **economic assumptions** are the forecast prices and costs used in the estimate.

    Development and Production Status

    Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) 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 (for example, 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.

(i) 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.

(ii) 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.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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 classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve 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 are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative 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 will be 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.

5. **exploratory well** means a well that is not a development well, a service well or a stratigraphic test well.

6. **development costs** mean costs incurred to obtain access to our reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from our reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

7. **development well** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

8. **exploration costs** mean costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. **service well** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, carbon dioxide or fuel gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. forecast prices and costs

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

11. Numbers may not add due to rounding.

12. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts ("**IQRE Average Forecast**") by McDaniel & Associates Consultants Ltd, GLJ and Sproule Petroleum Consultants, The IQRE Average Forecast is dated January 1, 2023. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2022

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
YEAR	WTI CUSHING OKLAHOMA ($US/Bbl)	CANADIAN LIGHT SWEET 40° API ($/Bbl)	WESTERN CANADA SELECT 20.5 API ($/Bbl)	CROMER MEDIUM 29° API ($/Bbl)	AECO GAS PRICE ($/MMbtu)	EDMONTON PROPANE ($/Bbl)	EDMONTON BUTANE ($/Bbl)	INFLATION RATES %/Year (1)	EXCHANGE RATE ($US/$) (2)
Forecast									
2023	80.33	103.77	76.54	99.97	4.23	39.80	53.88	0.0	0.7450
2024	78.50	97.74	77.75	94.17	4.40	39.13	52.67	2.3	0.7650
2025	76.95	95.27	77.54	91.78	4.21	39.74	51.42	2.0	0.7683
2026	77.61	95.58	80.07	92.10	4.27	39.86	51.61	2.0	0.7717
2027	79.16	97.07	81.89	93.53	4.34	40.47	52.39	2.0	0.7750
2028	80.75	99.01	84.02	95.40	4.43	41.28	53.44	2.0	0.7750
2029	82.36	100.99	85.73	97.31	4.51	42.11	54.51	2.0	0.7750
2030	84.01	103.01	87.44	99.25	4.60	42.95	55.60	2.0	0.7750
2031	85.69	105.07	89.20	101.24	4.69	43.81	56.71	2.0	0.7750
2032	87.40	106.69	91.11	102.80	4.79	44.47	57.56	2.0	0.7750
2033	89.15	108.83	92.93	104.86	4.89	45.35	58.71	2.0	0.7750
2034	90.93	111.00	94.79	106.95	4.98	46.26	59.88	2.0	0.7750
2035	92.75	113.22	96.68	109.09	5.08	47.19	61.08	2.0	0.7750
2036	94.60	115.49	98.62	111.27	5.18	48.13	62.30	2.0	0.7750
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.7750

Notes:

(1) Inflation rate for operating and capital costs.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices we realized for the year ended December 31, 2022, excluding price risk management activities, were $109.09/Bbl for light and medium crude oil, $97.23/Bbl for heavy crude oil, $5.65/Mcf for natural gas and $54.98/Bbl for NGLs.

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2022, using forecast price and cost estimates derived from the Report.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL[(2)]			HEAVY CRUDE OIL		
	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)
December 31, 2021	**47,080**	**16,484**	**63,563**	**25,427**	**6,690**	**32,117**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [(1)]	2,210	491	2,702	1,046	898	1,944
Technical Revisions [(2)]	1,764	(1,285)	480	1,296	149	1,444
Acquisitions [(3)]	213	35	248	-	-	-
Dispositions [(4)]	-	-	-	(322)	(71)	(393)
Economic Factors [(5)]	1,823	302	2,125	1,216	310	1,526
Production	(3,888)	-	(3,888)	(2,711)	-	(2,711)
December 31, 2022	**49,203**	**16,027**	**65,230**	**25,951**	**7,976**	**33,927**

	CONVENTIONAL NATURAL GAS			NATURAL GAS LIQUIDS		
	GROSS PROVED (MMcf)	GROSS PROBABLE (MMcf)	GROSS PROVED PLUS PROBABLE (MMcf)	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)
December 31, 2021	**46,120**	**16,665**	**62,785**	**3,178**	**1,068**	**4,246**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [(1)]	2,545	61	2,606	43	2	45
Technical Revisions [(2)]	(3,577)	(1,059)	(4,636)	(32)	(79)	(111)
Acquisitions [(3)]	6	3	8	2	1	3
Dispositions [(4)]	(27)	(6)	(33)	-	-	-
Economic Factors [(5)]	3,443	660	4,103	79	28	107
Production	(5,434)	-	(5,434)	(317)	-	(317)
December 31, 2022	**43,075**	**16,324**	**59,399**	**2,955**	**1,019**	**3,974**

Notes:

(1) Includes the expansion or increased recovery factor for existing reservoirs as a result of additional step-out drilling, infill drilling or enhanced oil recovery.

(2) Technical revisions are due to changes in previously booked estimates. In 2022, these revisions were: (i) positive light and medium crude oil revisions in the Bantry, Killam North and Midale areas; (ii) positive heavy crude oil reserves revisions in the Chauvin, Tide Lake, Viking Kinsella and Wainwright areas; and (iii) negative natural gas and associated natural gas liquids reserve revisions in the Knopcik and Mitsue areas due to lower solution gas recovery and suspended production.

(3) Positive additions to volume estimates from purchasing interests in oil and gas properties. Acquisition added volumes in the House Mountain and Loon areas.

(4) Dispositions are reductions in volume estimates due to selling all or a portion of an interest in oil and gas properties. Dispositions occurred in the Jenner area.

(5) The economic factors amount is the change in reserves due to changes in product pricing. The 2022 IQRE Average Forecast was higher in all product types than was the 2021 forecast.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (such as pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		HEAVY CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	233	4,518	-	1,845	419	2,531	3	226
2021	268	5,032	457	1,604	333	2,184	8	195
2022	170	4,650	-	1,178	29	1,795	-	191

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. GLJ has assigned 6.3 MMBoe of proved undeveloped reserves in the Report with $97 million of associated undiscounted capital, of which $50 million is forecast to be spent in the first two years. A total of $89 million of associated undiscounted capital is forecast to be spent in the first four years. The majority of the capital forecast after four years is associated with future development and CO_2 purchases for the enhanced recovery project in our Midale property. This is consistent with the long term development nature of CO_2 enhanced recovery projects. Development of other properties scheduled beyond two years is associated with properties which are being exploited at a controlled pace. The pace of development could be accelerated from that scheduled and is typically dependent on capital allocation.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		HEAVY CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	34	3,750	-	1,629	61	1,906	-	140
2021	172	3,713	154	1,399	113	1,674	3	110
2022	284	3,702	-	1,715	49	1,664	-	107

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. GLJ has assigned 5.8 MMBoe of probable undeveloped reserves in the Report with $37 million of associated undiscounted capital, of which $32 million is forecast to be spent in the first four years. Any capital forecast after four years is associated with future development and CO_2 purchases for the enhanced recovery project in our Midale property. This is consistent with the long term development nature of CO_2 enhanced recovery projects.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under the heading "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, we expect to fund the development costs of our reserves through a combination of internally generated cash flow from operating activities, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Report. Failure to develop those reserves could have a negative impact on our future cash flow from operating activities. Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for wells, facilities, pipelines and surface leases.

Our model for estimating the amount of future abandonment and reclamation expenditures is done on an individual well and facility level. Each well and facility is assigned an average cost for abandonment and reclamation over its useful life. Timing of expenditures takes into account seasonal access, priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. Facility reclamation costs are generally scheduled to begin at the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that plant/facilities are generally mobile assets with a long useful life. No estimate of salvage value is netted against the estimated cost.

The Report deducted $600 million undiscounted (and inflated by two percent) and $72 million discounted at 10% for the costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned from the estimates of the future net revenue disclosed in this Annual Information Form.

An additional $8 million undiscounted (and inflated by two percent) was deducted for the total proved plus probable undeveloped locations assigned reserves.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below using forecast prices and costs.

	FORECAST PRICES AND COSTS	
YEAR	PROVED RESERVES (1) ($MM)	PROVED PLUS PROBABLE RESERVES (1) ($MM)
2023	28	36
2024	37	42
2025	28	38
2026	18	27
2027	11	7
Remaining	59	75
Total (Undiscounted)	181	225
Discounted (10%)	122	150

Note:

(1) Includes $47 million and $55 million associated with proved and proved plus probable reserves respectively, for the purchase of CO_2 for the enhanced recovery schemes in the Midale area.

We ordinarily expect to fund the development costs of our reserves through a combination of internally generated cash flow from operating activities, debt and equity issuances.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Report. Failure to develop those reserves could have a negative impact on our future cash flow from operating activities.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2022. Information in respect of current production is average production, net to our working interest, except where otherwise indicated. We operate approximately 97% of our production. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The production in this section is shown on a boe basis. See the Production History section below for disaggregated production.

Bantry, Alberta

Bantry, which includes the Tide Lake, Alderson, Duchess, Rosemary and Kinnivie areas, is located near Brooks, Alberta. Bantry's average 2022 production was approximately 5,601 Boe/d (49% light and medium crude oil, 32% heavy oil, 17% conventional natural gas and 1% NGLs). The majority of our oil in this area is pipeline-connected to Cardinal-operated facilities, and is sales line connected to the Bow River South oil transmission system. The majority of our produced natural gas is conserved and sold through these Cardinal facilities, or third party facilities.

The majority of our crude oil production is from the Upper Mannville Glauconitic and Lower Mannville Ellerslie formations. Dominantly fluvial in nature, lower Mannville Ellerslie strata accumulated within valleys overlying the pre-Cretaceous unconformity in the Bantry area. Generally hydrocarbon charged, reservoir quality varies materially throughout the area. Oil accumulations are typically trapped stratigraphically by shale and tight siltstones. Current activity is focused on expanding known pool areas through horizontal drilling.

Upper Mannville Glauconite incised channels in the Bantry area are typically lithic in composition and transport erosional sediments from southerly highlands to the Clearwater sea to the north. Generally hydrocarbon charged, these channels are identified through a combination of existing vertical well control and 3D seismic data. Current development is focused on extending and infilling existing known channel trends.

The majority of these producing oil reservoirs are under enhanced recovery in the form of waterflood. We have identified areas where we can optimize existing waterfloods to further enhance oil recoveries. Optimization of these waterfloods, to further enhance oil recovery, is continually underway.

In 2022, we continued our drilling program in Bantry, drilling three (3.0 net) Glauconitic horizontal wells, four (4.0 net) multi-leg Ellerslie horizontal wells, five (5.0 net) single-legged horizontal Ellerslie wells and one (1.0 net) unsuccessful exploratory well. We currently plan to drill four (4.0 net) additional wells in our Bantry area during 2023.

Mitsue, Alberta

Our Mitsue property is located approximately 280 kilometers north of Edmonton, Alberta. Average 2022 production for this property was 3,094 Boe/d (64% light and medium crude oil, 15% heavy oil, 4% NGLs and 16% conventional natural gas) with a low decline production profile. The majority of the production is from the Mitsue Gilwood Sand Units. Wells are pipeline-connected to oil battery sites and a main gas plant where the oil and natural gas are connected to sales pipelines. We operate the wells and facilities within the Mitsue Gilwood Sand Units.

The Mitsue Gilwood A Pool was discovered in 1964 and produces 43° API oil from the Gilwood sandstone of the Middle Devonian Watt Mountain formation. Mitsue oil is trapped at the up-dip depositional edge in high quality deltaic sandstones of the Gilwood member. The reservoir is approximately 120,000 acres in size, one of the largest sandstone reservoirs in Canada and it is drilled to a density of less than one well per quarter section. Future opportunities include both vertical and horizontal infill drilling, and ongoing optimization of the existing waterflood.

Additionally, recent activity north of the Mitsue unit, at our Nipisi project began in 2022. This development is focused on oil targets in Mannville aged, regional marine sands of the Clearwater formation. Development targeting stratigraphically trapped 18-20° API heavy oil, using open-hole horizontal multilateral drilling is ongoing, with long term waterflood optimization being assessed.

During 2022, we drilled 4 (4.0 net) operated wells on the Nipisi lands and one (0.75 net) non-operated well into a separate, nearby Clearwater pool. During 2023, we plan to drill an additional five (5.0 net) operated wells within this play.

House Mountain, Alberta

House Mountain is located approximately 50 kilometers from our Mitsue field and approximately 280 kilometers north of Edmonton. The property includes an average 88% operated interest in four light oil producing units as well as a 100% interest in various non-unit lands.

The House Mountain property initially discovered in 1963 is developed with vertical and horizontal wells producing 41° API oil from the Slave Point and Swan Hills carbonates of the Devonian Beaverhill Lake Group. Oil is trapped at the depositional up-dip edge of a complex carbonate platform. This reservoir has been produced under enhanced recovery, in the form of waterfloods, which have been active since 1965. The current watercut from the pool is approximately 75%. This low watercut suggests significant remaining recoverable oil. Numerous optimization and field operating cost reduction opportunities are available on these assets. We have identified further drilling exploitation opportunities consisting of horizontal wells in the platform and vertical wells in the fringing reef.

The wells are pipeline-connected to the main oil battery. The oil is sales line connected, NGLs are trucked and the gas is conserved on site for power generation. The gas is contracted to a joint venture power station and is not sold in the market. Produced water is separated and re-injected to support the existing waterfloods.

The House Mountain assets averaged 1,939 Boe/d (91% light and medium crude oil and 9% NGLs) during 2022.

Grande Prairie, Alberta

The Grande Prairie assets are located to the west and to the north of the City of Grande Prairie, including the Wapiti and Knopcik areas and also include our Worsley and Mica, British Columbia areas. In aggregate, during 2022, this property produced 1,847 Boe/d (29% light and medium crude oil, 25% NGLs and 46% conventional natural gas). The main producing horizons include Cretaceous Dunvegan sandstones and Triassic aged carbonates and sandstones. Multiple infill drilling and extension opportunities are planned over the next several years at our Knopcik Dunvegan oil development along with further select oil development potential in the Triassic at Mica. The majority of our production here is pipeline-connected and operated, however natural gas is generally processed through third party facilities.

During 2022, our successful development continued in this area, with two (1.9 net) new horizontal wells drilled into the Dunvegan horizon at our Elmworth field. Currently, our 2023 budget includes no drilling in this area.

Wainwright, Alberta

Wainwright is located 195 kilometers southeast of Edmonton. The Wainwright properties include the Chauvin, Forestburg and Hayter areas, as well as our Killam and Viking-Kinsella areas which were acquired during 2021. Combined, in 2022, this property produced approximately 5,750 Boe/d (7% light and medium crude oil, 90% heavy oil and 3% conventional natural gas). The base production in Wainwright has a low production decline of approximately 6% per year. The majority of production is pipeline-connected.

The Wainwright properties primarily produce from the Middle Mannville Sparky formation which is a sandstone shale sequence deposited in a shallow-water progradational delta environment. The productive interval of the Sparky formation consists of coarsening-upward sequences with sandstones that are both fine and coarse grained. The Sparky sandstone responds favorably to enhanced recovery. Our producing reservoirs are under enhanced recovery, in the form of waterflood.

Further opportunity in this area exists in the exploitation of the Rex, Sparky, GP and Waseca sandstones by drilling horizontally into this channel facies at the base of the Upper Mannville. There are also infill horizontal drilling prospects in the Cummings formation in the Hayter area.

During 2022, we successfully drilled one (1.0 net) new multi-leg horizontal well, and one (1.0 net) horizontal leg addition in the Wainwright area. Our 2023 budget includes the drilling of four (4.0 net) wells in this area.

Midale, Saskatchewan

The Midale property is located in southeast Saskatchewan approximately 150 kilometers south and east of Regina. The Midale assets consist of operated production from the Midale Unit where we hold a 77% working interest. We also hold interests in a small amount of non-unit land in the Midale area, as well as a minor interest in the Weyburn Unit. The Midale and Weyburn Units are two of the lowest decline oil units in Western Canada at less than 5% and both units have significant development drilling upside. Our average 2022 production from these properties was 3,238 Bbls/d of 29° API light/medium oil.

The Midale Unit was discovered in 1953 and is part of a large Mississippian oil trend in the Williston Basin. The production interval is from the Midale Carbonate overlain and underlain from impervious anhydrite beds. The gross interval is subdivided into the Marly and the Vuggy intervals. Vertical and horizontal well development currently exploits both intervals. The Midale Unit waterflood was implemented in 1963. In 2005, the first of three stages of the current CO_2 EOR scheme was implemented. Currently the unit is operating with approximately 70% of the production supported by waterflood, while nearly half of this waterflood area is also supported by CO_2 injection. The CO_2 EOR scheme provides incremental oil recovery beyond that of the waterflood alone. The wells are pipeline-connected to a main oil battery supporting the water, gas and CO_2 injection. The oil is pipeline-connected to sales and the produced gas is combined with CO_2 for reinjection into the reservoir.

During 2022, we drilled two (1.5 net) horizontal production wells at Midale, along with two (1.5 net) horizontal injection wells to enhance and expand our EOR scheme. In 2023, we plan to drill six (4.6) wells into this development. The intent of these drills is to add three (2.3 net) injection wells and three (2.3 net) producing oil wells.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2022.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING		PRODUCING		NON-PRODUCING	
	Gross	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,693	1,426	932	648	151	91	179	110
British Columbia	13	12	6	4	2	2	7	6
Saskatchewan	654	179	191	48	-	-	-	-
Total	2,360	1,617	1,129	700	153	93	186	116

Note:

(1) This table excludes abandoned and service wells such as: water source, water injection and disposal wells.

Of the non-producing wells, 71 gross (48 net) were capable of production and had reserves assigned to them. As of the date of this Annual Information Form, 23 gross (18 net) of these wells had been on production within the last 24 months.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2022.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	165,851	106,300	481,671	335,931	647,521	442,230
British Columbia	5,715	5,208	11,218	9,590	16,933	14,798
Saskatchewan	22,585	17,203	30,716	25,517	53,301	42,719
Total	194,151	128,711	523,605	371,038	717,755	499,747

Notes:

(1) Rights to explore, develop and exploit 9,148 net acres of our land holdings could expire by December 31, 2023 if not continued.

(2) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported only once. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Properties with no Attributed Reserves

As at December 31, 2022 we held 333,981 gross acres (214,768 net acres) to which no reserves are currently attributed, all of which are located in Canada. Rights to explore, develop and exploit 5,152 net acres of these land holdings could expire by December 31, 2023 if not continued. We have no material work commitments other than abandonment obligations on these properties and the majority of this acreage is located in our non-core operating areas. When determining gross and net acreage, where we hold two or more leases granting stratigraphic interests which overlap geographically, the acreage is reported for each lease; where we hold two or more stratigraphic interests in a single lease that overlap geographically, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties With no Attributed Reserves

Our asset base focuses on sustainable low decline production with little capital allocated to the exploration or development of properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. In addition, there are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. All abandonment and reclamation costs have been included in the Report, including costs for properties with no attributed reserves. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

Our operational results and financial condition are dependent upon the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors, supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition.

We have a hedging policy using, amongst others, collars, puts and fixed price swaps which allows us to hedge our gross oil, NGLs and natural gas forward production profile of three years, of up to 75% of average forward 12 months production and up to 50% and 30% of the following 12 and 24 months, respectively. These hedging activities could expose us to losses or gains. See "*Risk Factors – Hedging*".

In 2022 and into 2023, Cardinal has remained largely unhedged due to backwardated forward pricing curves and reduced corporate financial risk with significantly lower debt levels. For further information, see note 17 to our financial statements for the year ended December 31, 2022.

Tax Horizon

Based on the current tax regime, our tax attributes, expected cash flow from operating activities and capital expenditures, we do not expect income taxes to become payable until 2026, or beyond.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2022.

EXPENDITURE	**YEAR ENDED DECEMBER 31, 2022 ($000s)**
Property acquisition costs – Unproved properties [(1)]	6,894
Property acquisition costs – Proved properties	2,432
Property dispositions – Proved properties	(425)
Exploration costs [(2)]	928
Development costs [(3)]	107,600
Total	117,429

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Geological and geophysical capital expenditures and drilling costs for exploration wells and stratigraphic test wells.
(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(4) Expenditures do not include office equipment, capitalized general and administrative costs and related share based compensation or non-cash expenditures for the abandonment and decommissioning obligation. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*".

Exploration and Development Activities

The following table sets forth the gross and net development wells in which we participated during the year ended December 31, 2022.

	DEVELOPMENT		EXPLORATORY (1)	
	GROSS	NET	GROSS	NET
Conventional Natural Gas	-	-	-	-
Light and Medium Crude Oil	5	4.5	-	-
Heavy Crude Oil	18	17.8	-	-
Dry	-	-	1	1.0
Service	2	1.5	-	-
Total	25	23.8	1	1.0

Cardinal expects to maintain activities in and around its current core areas and concentrated on oil development.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2022, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the heading "*Disclosure of Reserves Data*".

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	HEAVY CRUDE OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE (Boe/d)
Proved	10,934	6,665	15,022	824	20,927
Probable	445	411	530	20	965
Proved plus Probable	11,380	7,076	15,552	844	21,891

Note:

(1) No one field represents more than 20% of our forecast production.

Production History

The following table indicates our average daily production for the year ended December 31, 2022.

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	HEAVY CRUDE OIL (Bbls/d)	NATURAL GAS LIQUIDS (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	BOE (Boe/d)
Bantry (1)	2,750	1,801	71	5,879	5,601
Grande Prairie	538	-	463	5,079	1,847
House Mountain	1,764	-	176	-	1,939
Mitsue (2)	1,982	477	139	2,981	3,094
Wainwright (3)	423	5,160	2	994	5,750
Midale, SK	3,238	-	-	-	3,238
Total	10,695	7,438	851	14,933	21,471

Notes:

(1) Includes the Alderson, Duchess, Rosemary, Kinnivie and Tide Lake areas.
(2) Includes the Nipisi, Worsley and Mica areas.
(3) Includes the Chauvin, Forestburg, Hayter, Killam North and Kinsella areas.

The following table summarizes certain information in respect of our production, product prices received, royalties, operating costs and resulting netback for the periods indicated below:

	QUARTER ENDED 2022 MAR. 31	JUNE 30	SEPT. 30	DEC. 31	YEAR ENDED DEC. 31, 2022
Average Daily Production (1)					
Light and Medium Crude Oil (Bbls/d)	10,788	10,813	10,712	10,466	10,694
Heavy Crude Oil (Bbls/d)	6,690	7,954	7,618	7,476	7,437
Natural Gas Liquids (Bbls/d)	804	928	870	802	851
Conventional Natural Gas (Mcf/d)	13,888	15,511	15,095	15,222	14,933
Combined (Boe/d)	20,596	22,280	21,715	21,281	21,471
Average Prices Received					
Light and Medium Crude Oil ($/Bbl)	107.07	128.27	105.49	95.19	109.09
Heavy Crude Oil ($/Bbl)	100.05	120.16	92.18	75.75	97.23
Natural Gas Liquids ($/Bbl)	54.24	60.51	55.24	49.08	54.98
Conventional Natural Gas ($/Mcf)	4.97	7.52	4.65	5.37	5.65
Combined ($/Boe)	94.05	112.91	89.82	79.11	94.12
Royalties					
Light and Medium Crude Oil ($/Bbl)	22.84	27.64	24.80	19.85	23.81
Heavy Crude Oil ($/Bbl)	17.85	23.07	18.16	14.01	18.35
Natural Gas Liquids ($/Bbl)	13.61	14.02	11.32	10.14	12.30
Conventional Natural Gas ($/Mcf)	0.47	0.87	0.67	0.50	0.63
Combined ($/Boe)	18.61	22.84	19.52	15.43	19.14
Operating Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	27.21	25.93	30.57	28.87	28.19
Heavy Crude Oil ($/Bbl)	28.35	26.62	31.68	30.38	29.20
Natural Gas Liquids ($/Bbl)	6.48	6.29	6.42	9.68	7.18
Conventional Natural Gas ($/Mcf)	0.72	0.64	0.56	0.76	0.67
Combined ($/Boe)	24.35	22.69	26.75	25.72	24.88
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.57	0.42	0.30	0.54	0.46
Heavy Crude Oil ($/Bbl)	0.55	0.77	0.95	0.75	0.76
Natural Gas Liquids ($/Bbl)	2.30	2.22	1.99	2.53	2.25
Conventional Natural Gas ($/Mcf)	0.30	0.29	0.26	0.26	0.28
Combined ($/Boe)	0.62	0.87	0.83	0.87	0.80
Resulting Netback (4)					
Light and Medium Crude Oil ($/Bbl)	56.45	74.28	49.82	45.93	56.63
Heavy Crude Oil ($/Bbl)	53.30	69.70	41.39	30.61	48.92
Natural Gas Liquids ($/Bbl)	31.85	37.99	35.50	26.74	33.25
Conventional Natural Gas ($/Mcf)	3.48	5.72	3.16	3.86	4.08
Combined ($/Boe)	50.47	66.51	42.72	37.09	49.30

Notes:

(1) Before the deduction of royalties.

(2) These are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.

(3) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

(4) Netback is a Non-GAAP measure. Refer to the section entitled "Non-IFRS and Other Financial Measures" contained within our MD&A for the year ended December 31, 2022, available on SEDAR at www.sedar.com, for certain additional disclosures relating to this non-GAAP measure, which information is incorporated in this Annual Information Form by reference.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Share Capital

We are authorized to issue an unlimited number of Common Shares without nominal or par value and an unlimited number of first preferred shares. A description of our share capital is set forth below. For a complete description of our share capital, reference should be made to our Articles, a copy of which has been filed on SEDAR at *www.sedar.com*.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of shares other than our Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to other classes of shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all other classes of shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares ranking equally with the Common Shares, in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

If our Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares referred to as a "stock dividend"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) the "Average Market Price" of a Common Share on the Toronto Stock Exchange, with the "Average Market Price" calculated by dividing the total value of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) by the total volume of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Share payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to our transfer agent as the agent of such registered holders of Common Shares. Our transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by us by way of stock dividends in respect of the Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by our transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time we have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a Shareholder in Common Shares, we have the right to sell, or to require our transfer agent in each case as agent of such Shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, and to cause our transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by us to such holder and to us or our transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which we have reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and Cardinal or our transfer agent as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of us. Any balance of the cash sale proceeds not remitted by us in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time we shall have reason to believe that the payment of a stock dividend to any holder who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject us to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to us, we shall have the right to sell, or to require our transfer agent in each case, as agent of such Shareholder, to sell through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause our transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject us to any penalty or legal or regulatory requirement. Upon receipt of the notice, we or our transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and we or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from our transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by our transfer agent for the account of such holder and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by us prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a Shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither us nor our transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a Shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which we and/or our transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

First Preferred Shares

Voting Rights: Holders of first preferred shares shall be entitled to receive notice of, to attend and to one vote per first preferred share held at any meeting of the Shareholders (other than meetings of a class or series of shares of Cardinal other than the first preferred shares as such).

Dividends: Holders of first preferred shares shall be entitled to receive if, as and when declared by our Board of Directors out of the monies of our applicable to the payment of dividends, such dividends in any financial year as the Board of Directors in its absolute discretion may by resolution determine, and the directors may, subject to certain restrictions on dividends, declare dividends on any other class of share at different times or at the same time in different amounts than dividends declared on the first preferred shares.

Ranking: In the event of the liquidation, dissolution or winding up of us or other distribution of our assets among Shareholders for the purpose of winding up our affairs, the holders of first preferred shares shall be entitled to receive the redemption value of the first preferred shares per share, together with any accrued and unpaid dividends thereon up to the date of commencement of any such liquidation, dissolution, winding up or other distribution of our assets and to be paid all such money before any money shall be paid or property or assets distributed to the holders of any Common Shares or other shares in our capital ranking junior to the first preferred shares with respect to return of capital. After payment to the holders of the first preferred shares of the amounts so payable to them in accordance, the holders of first preferred shares shall not be entitled to share in any further distribution of our property or assets.

Credit Facility

The Credit Facility of $155 million is comprised of a $135 million syndicated term credit facility and a $20 million non-syndicated operating line credit facility. The Credit Facility is available on a revolving basis until May 31, 2023 and may be extended for a further 364 day period, subject to approval by the syndicate. If not extended, the Credit Facility will cease to revolve, the applicable margins will increase by 0.5% and all outstanding advances will be repayable on May 31, 2024. On the redetermination date, the lenders could reduce the borrowing base to below the current drawn amount, in this case, the short fall would have to be repaid within 30 days.

The available lending limits of the Credit Facility are reviewed semi-annually based on the syndicate's interpretation of our reserves, future commodity prices and costs. As the available lending limit of the Credit Facility is based on the syndicate's interpretation of our reserves and future commodity prices and costs, there can be no assurance that the amount of the Credit Facility will not decrease at the next scheduled review. On a redetermination date, lenders could reduce the borrowing base to below amounts drawn, in which case, any short fall would have to be repaid within 60 days. The next scheduled review date is on or before May 31, 2023.

Advances under the Credit Facility are available by way of either prime rate loans, which bear interest at the banks' prime lending rate plus 1.75 to 5.25%, or bankers' acceptances, which are subject to fees and margins ranging from 2.75 to 6.25%. Interest and standby fees on the undrawn amounts of the Credit Facility depend upon certain ratios.

The Credit Facility is secured by a general security agreement over all of our assets. There are no financial covenants related to the Credit Facility, provided that we are not in default of the terms of the Credit Facility. See "*Risk Factors – Credit Facility Arrangements*".

MARKET FOR OUR SECURITIES

Trading Price and Volume

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "CJ" and commenced trading on the Toronto Stock Exchange on December 17, 2013. The following table sets out the high and low trading prices and aggregate volume of trading for the periods noted below for our Common Shares, as reported by the Toronto Stock Exchange.

PERIOD	HIGH	LOW	VOLUME
2022			
January	5.47	4.34	20,745,304
February	6.53	5.02	24,087,471
March	8.35	6.71	35,395,249
April	7.86	6.37	20,610,050
May	9.73	6.43	36,650,602
June	9.53	6.80	42,685,833
July	9.30	6.26	28,636,124
August	9.36	8.04	24,282,306
September	8.36	6.64	27,447,516
October	9.65	7.38	20,693,559
November	9.96	8.06	27,420,346
December	8.32	6.74	20,521,599
2023			
January	8.04	6.85	20,383,284
February	7.63	7.08	20,314,290
March (to March 27)	7.52	6.39	26,814,336

Prior Sales

During the year ended December 31, 2022 we granted a total of 1.2 million performance and restricted awards pursuant to our bonus award incentive plan. On the payment date of the bonus awards, we have the sole discretion as to whether the bonus awards are paid in cash, Common Shares from treasury or Common Shares purchased on the market. No other share-based compensation was granted by us during the year ended December 31, 2022. See note 14 of our annual financial statements for the year ended December 31, 2022 for further information.

DIRECTORS AND OFFICERS

Summary Information

The following table sets forth certain summary information in respect of our directors and executive officers as at the date of this Annual Information Form.

NAME, PROVINCE AND COUNTRY OF RESIDENCE	POSITION HELD	PRINCIPAL OCCUPATION FOR THE LAST FIVE YEARS	DIRECTOR SINCE
M. Scott Ratushny (3) Alberta, Canada	Chief Executive Officer and Chair	Our Chair and Chief Executive Officer since July 6, 2012. Prior thereto, Chair and Chief Executive Officer of Midway Energy Ltd., a public oil and gas company.	May 2011
Stephanie Sterling (1)(2)(3)(4)(5) Alberta, Canada	Lead Director	Lead Independent director. Ms. Sterling is a retired senior executive with Shell Canada with over 25 years' experience. Ms. Sterling has also been a director of the Alberta Petroleum Marketing Commission, a Crown board, since July 2017 and a director of Cabin Ridge Project Limited, a private coal mining company, since April, 2020. She previously served on the board of Riversdale Resources Limited, a private coal development company from 2017 to 2019.	August 2017
John A. Brussa (4)(5) Alberta, Canada	Director	Mr. Brussa is a partner and Chair of Burnet, Duckworth & Palmer LLP.	July 2012
David D. Johnson (1)(2)(3)(4)(5) Alberta, Canada	Director	Independent Businessperson. Mr. Johnson was the Chair of Progress Energy Resources Corp., a public oil and gas company, prior to its sale on December 12, 2012.	July 2012
John Gordon (1)(2) Alberta, Canada	Director	Mr. Gordon served as the Canadian Managing Partner, Quality and Risk Management, the Canadian Managing Partner, Audit and the Calgary Office Managing Partner for KPMG LLP prior to his retirement in 2018. Mr. Gordon has extensive experience in providing audit and other services to public oil and gas companies. Mr. Gordon is a Chartered Professional Accountant (FCPA), a Chartered Financial Analyst (CFA) charter holder, and is a graduate of the University of Saskatchewan. Mr. Gordon serves on the Board of the CAMH Foundation, and is a lecturer for, and an active member of the Institute of Corporate Directors.	May 2021
Dale Orton Alberta, Canada	Chief Operating Officer	Our Chief Operating Officer since November 9, 2017. Prior thereto, our Vice President since December 1, 2016. Prior thereto, Senior Vice President, Development for Long Run Exploration Ltd., a public oil and gas company.	N/A
Shawn Van Spankeren Alberta, Canada	Chief Financial Officer	Our Chief Financial Officer since January 15, 2018. Prior thereto Vice-President, Finance and Administration, Crew Energy Inc. since October 2013. Prior thereto, Vice-President, Finance & Controller, Crew Energy Inc. since January 2009.	N/A

NAME, PROVINCE AND COUNTRY OF RESIDENCE	POSITION HELD	PRINCIPAL OCCUPATION FOR THE LAST FIVE YEARS	DIRECTOR SINCE
Robert Wollmann Alberta, Canada	Senior Vice President, Exploration	Our Senior Vice President Exploration since November, 2017. Prior thereto, President, Long Run Exploration Ltd since April 2017. Prior thereto, President & CEO, Twin Butte Energy Ltd. since May 2014. Prior thereto, Senior Vice President, Exploration, Penn West Petroleum Ltd. since February 2012.	N/A
Laurence Broos Alberta, Canada	Vice President, Finance	Our Vice President, Finance since February 10, 2015. Prior thereto, Treasurer of Penn West Petroleum Ltd.	N/A
Connie Shevkenek Alberta, Canada	Vice President, Engineering	Our Vice President, Engineering since September 1, 2016. Prior thereto, our Manager of Engineering since February, 2014. Prior thereto, Vice President of Business Development at Flagstone Energy Inc.	N/A
Wes Heatherington Alberta, Canada	Vice President, North	Our Vice President, North since June 2018. Prior thereto, Vice-President Production at Long Run Exploration Ltd. since November, 2016. Prior thereto, Senior Production Manager at Long Run Exploration Ltd. since June, 2011.	N/A
Jason LaForge Alberta, Canada	Vice President, Central	Our Vice President, Central since November 9, 2017. Prior thereto, our area manager of the Central area since September, 2017. Prior thereto, Vice President Operations at Muirfield Resources Ltd.	N/A
Ken Younger Alberta, Canada	Vice President, South	Our Vice President, South since March 2018. Prior thereto, our area manager of the South area since April 2016. Prior thereto, Manager of Production at Spur Resources Ltd. since August, 2010.	N/A
David Kelly Alberta, Canada	Vice President, Saskatchewan	Our Vice President, Saskatchewan since September 2017. Prior thereto, Vice-President, Production & Operations at Gain Energy Ltd. and Omers Energy Inc. since February 2017. Prior thereto, Production Manager with Omers Energy Inc. since June 2015.	N/A

Notes:

(1) Member of our Audit Committee. Mr. John Gordon is the Chair of the Audit Committee.
(2) Member of our Corporate Governance & Compensation Committee. Ms. Stephanie Sterling is the Chair of the Corporate Governance & Compensation Committee.
(3) Member of the Reserves Committee. Mr. David Johnson is the Chair of the Reserves Committee.
(4) Member of our Environmental, Social and Governance Committee. Ms. Stephanie Sterling is the Chair of the Environmental, Social and Governance Committee.
(5) Independent director.

All of our directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the *Business Corporations Act* (Alberta). Each director will devote the amount of time as is required to fulfill his or her obligations to us. Our officers are appointed by and serve at the discretion of the Board of Directors.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as discussed below, and to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as discussed below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

Mr. Brussa was formerly a director of Calmena Energy Services Inc. ("**Calmena**"), a public oilfield service company which was placed in receivership on January 20, 2015. Mr. Brussa resigned as a director of Calmena on June 30, 2014. Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Trust and its Canadian and United States holding companies (collectively "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* ("**CCAA**") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code* ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. Mr. Brussa resigned on June 30, 2016.

Messrs. Brussa and Ratushny were directors of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Each of Messrs. Brussa and Ratushny resigned as directors of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa resigned as a director on September 1, 2016 and Mr. Wollmann departed as President and CEO of Twin Butte Energy Ltd. ("**Twin Butte**"), a public oil and gas company, on September 2, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court of Queen's Bench of Alberta ("**Court**") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Messrs. Brussa and Johnson were directors of Virginia Hills Oil Corp. ("**VHO**"), a public oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Johnson resigned as a director of VHO on April 5, 2016 and Mr. Brussa resigned as a director of VHO on February 24, 2017.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

On June 30, 2005 the United States Securities and Exchange Commission ("**SEC**") issued a settlement order relating to certain administrative proceedings involving a number of parties including KPMG LLP and Mr. Gordon, a former partner of KPMG LLP. The SEC alleged that during the years 1999 to 2002, Mr. Gordon, while a partner at KPMG LLP, knew, in his role as concurring and reviewing audit partner, that certain accounting services were being provided by KPMG LLP to an SEC registrant, while KPMG LLP were also serving as auditors to the same registrant. KPMG received $60,148 in aggregate fees from the audit and bookkeeping services it performed for this registrant during this period. Under the terms of the settlement with the SEC, Mr. Gordon agreed not to appear or practice as an accountant before the SEC, with respect to SEC registrants, for a period of nine months, after which time, he was automatically reinstated.

Conflicts of Interest

Certain of our officers and directors are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to our best interests. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the *Business Corporations Act* (Alberta). The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his or her interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE

Audit Committee Mandate

The Board has adopted a written mandate and terms of reference for our Audit Committee, which sets out the Audit Committee's responsibility for, among other things, reviewing our financial statements and our public disclosure documents containing financial information and reporting on such review to the Board, ensuring our compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of our external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this Annual Information Form as Appendix C.

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee currently consists of John Gordon (Chair), David Johnson and Stephanie Sterling. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

We believe that each of the members of our Audit Committee possesses: (a) an understanding of the accounting principles used by us to prepare financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting. The relevant education and experience of each audit committee member is outlined below.

John Gordon:

Mr. Gordon served as the Canadian Managing Partner, Quality and Risk Management, the Canadian Managing Partner, Audit and the Calgary Office Managing Partner for KPMG LLP prior to his retirement in 2018. Mr. Gordon has extensive experience in providing audit and other services to public oil and gas companies. Mr. Gordon is a Chartered Professional Accountant (FCPA), a Chartered Financial Analyst (CFA) charter holder, and is a graduate of the University of Saskatchewan.

David D. Johnson:

Mr. Johnson has over 40 years of diverse experience in the oil and gas industry including a background in production, reservoir evaluation and operations. He has a B.Sc. in Petroleum Engineering, is a member of the Association of Professional Engineers and Geoscientists of Alberta and has served twice as a governor of the Canadian Association of Petroleum Producers.

Stephanie Sterling:

Ms. Sterling holds a Bachelor of Science (Mechanical Engineering) degree and an MBA from the University of Alberta. Ms. Sterling is a recently retired senior executive with Shell Canada with over 25 years' experience in engineering, large project start-up and operations, governance, joint venture negotiations and relationships, risk management, business development and strategic planning. She has served as General Manager for Non-Technical Risk Integration, Community and Indigenous Relations for Shell in Canada, USA and Latin America where she was responsible for integrating risk management into new projects. She also served as the Vice President Business and Joint Ventures for Shell's Heavy Oil business, where she was responsible for the joint venture governance, commercial negotiations and relationships for two significant joint ventures: the Athabasca Oil Sands Project among Shell, Chevron and Marathon; and the AERA joint venture in California between Shell and Exxon. Ms. Sterling also serves on the board of the Alberta Petroleum Marketing Commission, including the Audit Committee and Cabin Ridge Project Limited, a private coal mining company and previously served on the board and Audit Committee of Riversdale Resources Inc. from 2017 to 2019.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by us to our auditors, KPMG LLP, for external audit and other services during the period indicated.

YEAR	AUDIT FEES (1) ($)	AUDIT-RELATED FEES (2) ($)	TAX FEES (3) ($)	ALL OTHER FEES (4) ($)
2021	260,000	75,000	4,815	25,000
2022	290,000	75,000	5,083	-

Notes:

(1) Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as audit fees.

(3) Tax fees include tax compliance, tax advice, tax planning and compilation of tax returns.

(4) Other fees include additional work required to implement new accounting standards.

DIVIDEND POLICY

We started paying dividends on our Common Shares in 2014. We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve and on March 17, 2020, we suspended our dividend due to the economic environment. On May 12, 2022, we announced that our Board of Directors had approved the reinstatement of our monthly dividend starting at $0.05 per Common Share per month in June 2022. On September 12, 2022, we announced that our Board of Directors had approved an increase in our monthly dividend commencing in the fourth quarter of 2022 from $0.05 per Common Share to $0.06 per Common Share. The $0.06 per Common Share dividend continued for the first quarter 2023. See "*General Development of our Business – Recent Developments*".

Our long-term objective with respect to dividends is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to maintain or modestly grow our production base.

Cash dividends were paid on the 15th day (or if such date was not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us.

The payment and amount of dividends is determined in the sole discretion of our Board after considering a variety of factors and conditions existing from time to time, including current and future commodity prices, foreign exchange rates, our hedging program, current operations including production levels, operating costs, royalty burdens and debt service requirements, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

The following monthly cash dividends on our Common Shares were declared by our Board for the periods indicated:

PERIOD	DIVIDEND PER COMMON SHARE
September 2014 – December 2015	$0.07
January 2016 – December 2018	$0.035
January 2019 – June 2019	$0.01
July 2019 – February 2020	$0.015
March 2020 – May, 2022	Suspended
June 2022 – September, 2022	$0.05
October 2022 – March, 2023	$0.06

Unless otherwise specified, all dividends paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, among other things, no default, event of default or borrowing base shortfall exists, could reasonably be expected to result from, such declaration or payment.

INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of petroleum 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 Western Canadian oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future.

Our assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of our upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the provinces of Alberta, Saskatchewan and British Columbia, where our assets are primarily located. While these matters do not affect our operations 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 matters carefully.

Pricing and Marketing in Canada

Crude Oil

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

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

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

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. We do not directly enter into contracts to export our production outside of Canada.

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Oil Pipelines

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, 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 in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

Producers negotiate with pipeline operators to transport their products to market on a firm 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 price received.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of

Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the Court ruled that the Bad River Band is entitled to financial compensation, and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

Marine Tankers

The *Oil Tanker Moratorium Act* (Canada), which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Western Canada 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 more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**") and the expanded NGTL System was completed in April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement ("**CETA**"), the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Western Canada's oil and gas industry as a whole, including the Company's business.

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

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

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

Land Tenure

Mineral rights

With the exception of 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 (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. The provincial governments in Western Canada conduct regular 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.

In response to COVID-19, the Government of Alberta, among others, announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures.

All of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences; British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. We do not have operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. 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 oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, both the federal government and the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance. In addition, from time-to-time, including during the COVID-19 pandemic, the federal government has created incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

Alberta

Crown royalties

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

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

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Incentives

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

British Columbia

Crown royalties

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "**New Framework**") was announced in May 2022. The New Framework will increase the minimum royalty rate from 3% to 5%, and eliminate the Deep Well, Marginal Well, Ultramarginal Well, Low Productivity Well Rate Reduction and Clean Growth Infrastructure royalty programs (the "**Old Royalty Programs**"). New wells drilled under the New Framework will pay the flat royalty of 5% until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between 5% and 40%, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 will not be eligible to qualify for the Old Royalty Programs, and will pay a 5% royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until

September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

Under the current system, Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high as 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells under the Old Royalty Programs to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Saskatchewan

Crown royalties

Crown royalties payable on the production of oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of oil and natural gas receive royalty invoices from the Government on a monthly basis.

The Crown royalty payable on oil production is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of oil, the quantity of oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. Base royalty rates represent the minimum royalty rate payable on production of petroleum substances, regardless of the level of production. Marginal royalty rates charge increasing royalty rates as the level of production increases. Marginal royalty rates, such as those used in Saskatchewan's royalty regime, are designed to allow producers of petroleum products to more quickly recover initial investments at the beginning of a project's life cycle. The Crown royalty payable on natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $3.70 per-hectare owned regardless of whether or not there is production from the lands.

Resource Surcharge

In addition to royalties, certain entities operating in Saskatchewan must pay a tax, known as a "**Resource Surcharge**", on the value of resources sales. The Resource Surcharge rate is 3% of the sales value of all oil and natural gas produced from wells drilled in Saskatchewan before October 1, 2002, and 1.7% for any wells drilled thereafter.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is 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 gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**"), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

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

The CERA and the Impact Assessment Act (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

Alberta

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

The Government of Alberta's land-use policy sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. We routinely conduct hydraulic fracturing in our drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). We do no not have operations in any of these regions.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission ("**BC OGC**") has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC OGC to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. 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.

In November 2022, the Government of British Columbia passed the Energy Statutes Amendment Act, 2022 (the "**ESA Act**"). The ESA Act will see the name of the BC OGC changed to the British Columbia Energy Regulator, and its mandate will be expanded to include oversight of hydrogen, ammonia and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the Energy Resources Activities Act (the "**ERAA**"). In addition to expanding the British Columbia Energy

Regulator's jurisdiction to include hydrogen, ammonia and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

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 an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC OGC before resuming production. The permitting process requires all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC OGC issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BC OGC introduced enhancements to the Special Project Order in April 2021, expanding the boundaries of the order. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

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 statute 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 Petrinex Database delivers business processes and information required for the assessment, levy, and collection of crown royalties for Alberta, Saskatchewan and British Columbia. It provides information in support of the regulatory mandates and legislation of the provinces, and services that facilitate important industry commercial activities, including partner to partner reporting, oil marketing, financial analytics, compliance assurance and production accounting.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021 and further updates released in 2022. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new

Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of 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 licence transfer when any such 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. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first 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. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources and infrastructure; (iv) the management of its operations; (v) the rate of closure activities and spending, and pace of inactive liability growth; and (vi) and its compliance with administrative and regulatory requirements. These various factors feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The AER has also indicated that it will implement a closure nomination program (the "**CN Program**") in 2023. Under the program, those who qualify may nominate certain oil and gas sites for closure. Details regarding the CN Program and the mechanism through which nominated sites will be abandoned and reclaimed are forthcoming.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

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. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program was designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Parties seeking to participate in the program had to commit to an inactive liability reduction target to be met through closure work of inactive assets.

British Columbia

Similar to Alberta, the BC OGC has moved away from the formulaic approach to liability management set out in the Liability Management Rating Program, towards a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. The BC OGC implemented the Permittee Capability Assessment on April, 1 2022 (the "**BC PCA**"). Under the BC PCA, the financial risk of a permit holder is assessed based on its: (i) assets to liabilities ratio; (ii) net profit margin (three-year average); (iii) interest coverage ratio; (iv) cash flow to debt ratio; and (v) debt to equity ratio. A permit holder is assessed on these factors based on the financial information it is required to submit to the BC OGC intermittently throughout the year. The permit holder is then evaluated on the magnitude of its liabilities, based on the deemed abandonment, assessment, remediation and reclamation liability associated with the permit holder's dormant, inactive, and marginal sites. If the BC OGC deems a permit holder to be high-risk under the BC PCA based on its financial risk and the magnitude of its liabilities, the regulator may require that permit holder to engage in corrective action. Corrective action could include the submission of security deposits and/or the completion of liability reduction work. Regarding the latter, the BC OGC will attempt to engage with permit holders to develop corrective action plans prior to issuing corrective action requirements.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the 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 OGAA permits the BC OGC to impose more than one levy in a given calendar year.

The Dormancy and Shutdown Regulation (the "**Dormancy Regulation**") establishes 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 each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC OGC, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

The Government of British Columbia passed amendments to the Oil and Gas Activities Act under the Miscellaneous Statutes Amendment Act (No.2) in October 2021. These amendments allow the BC OGC to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set under the Dormancy Regulation. The relevant amendments which provide the BC OGC with the power to grant these exemptions came into force on October 28, 2021.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in January 2023. 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 SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, a licence transfer application must be completed through the Integrated Resource Information System ("**IRIS**"). An assessment is conducted on both the transferee and the transferor listed in the IRIS application. To complete the assessment, both a licensee liability rating ("**LLR**") assessment and a proportional risk transfer is conducted. If a licence transfer will result in either the transferor or transferee having an LLR of less than 1.0, the transferor or transferee, as applicable, shall submit the amount of security deposit required by the minister.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new Financial Security and Site Closure Regulations (the "**Closure Regulations**"), published in June 2021. The Closure Regulations came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012, (the "Conservation Regulations") remain in effect. Among other things, the Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on our operations and cash flow from operating activities.

Federal

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. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Prime Minister's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of CNEAA change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap for Canada's reduction of GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022 the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. Beginning in 2022, the federal government plans to spend $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $65 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims 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. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $65/tonne of CO2e, and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

In January 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. 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.

In December 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and

(vi) incentivizing the adoption of zero-emissions vehicles. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27-32% for the transportation sector, 38-43% for industry and 33-38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $83.5 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BC OGC implemented a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. In November 2020, the Government of Canada 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.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

Under the MRGGA, facilities that have annual GHG emissions in excess of 10,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program.

On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40-45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

The MRGGA and the Saskatchewan O&G Emissions Regulations meet the federal benchmark stringency requirements for certain industrial sectors, but the federal backstop continues to apply to emissions sources not covered in Saskatchewan's emissions legislation. The federal fuel charge continues to apply in Saskatchewan.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030. According to its 2020 and 2021 reports, the province generates nearly 26% of its electricity from renewable energy sources, an increase of 1.6% since 2019.

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 revised in August 2022, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020 and was last revised in June 2022. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide $500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be increasing investment in CCUS through enhanced oil recovery projects. In November 2021, Saskatchewan announced that pipelines transporting CO2 for CCUS are eligible for the provincial Oil Infrastructure Investment Program ("**OIIP**"). The Government of Saskatchewan expects that CCUS projects will attract provincial investment of more than $2 billion and sequester over two million tonnes of CO2 annually. OIIP will assist in generating a total investment impact of at least $500 million in new and expanded pipeline capacity in Saskatchewan, while encouraging industry adoption of CCUS and further reductions in greenhouse gas emissions.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, 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 UNDRIP, 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's principles.

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

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

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson, Salteau, Halfway River and Doig River First Nations – reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

Accountability and Transparency

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

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Prices, Markets and Marketing

Our ability to market our oil and natural gas may depend upon our ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of oil and NGLs by rail. Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us, including:

- deliverability uncertainties related to the distance our reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; 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 the world economies, the ongoing COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flow from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Market Access*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems, trucking and railway lines. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results.

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

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, we may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

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

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance and business interruption insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Insurance*" in these Risk Factors. In either event, we could incur significant costs.

Inflation and Cost Management

Our operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, power costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash flow from operating activities.

The cost or availability of oil and gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on our financial performance and cash flow from operating activities.

Availability of Supplies for EOR Schemes

We are reliant on the availability of water and CO_2 supplies for our EOR schemes. Should there be a disruption in the delivery or cessation of these supplies this could have a negative impact on the production of oil and natural gas and the associated reserves of these properties. Waterflood EOR schemes are those which involve the injection of water into an oil reservoir to maintain reservoir pressure. In most cases, the water produced is re-injected plus additional water sourced from compatible water bearing reservoirs or fresh water sources. There is no certainty that we will have access to the required volumes of water or CO_2 in the future.

Impact of Pandemics

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on our operational results and financial condition. Low prices for oil, liquids and natural gas will reduce our cash flow from operating activities, and impact our level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of our facilities.

The extent to which our operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than we do. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Reliance on a Skilled Workforce and Key Personnel

Our operations and management 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 our business plans which could have a material adverse effect on our business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. We do not have any key personnel insurance in effect. Contributions of the existing management team to our immediate and near-term operations are likely to be of central importance. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Market Price of our Common Shares

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of our Common Shares has been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Credit Facility Arrangements

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are required to comply with certain non-financial covenants under the Credit Facility and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, from time to time, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others. See "*Description of our Capital Structure – Credit Facility*".

Our lenders use our reserves, commodity prices, applicable discount rate and other factors to periodically determine our borrowing base. Any decrease in commodity prices could reduce our borrowing base, reducing the funds available to us under the Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

If our lenders require repayment of all or a portion of the amounts outstanding under our Credit Facility for any reason, including for a default of a covenant, or the reduction of a borrowing base, there is no certainty that we would be in a position to make such repayment. Even if we are able to obtain new financing in order to make any required repayment under our Credit Facility, it may not be on commercially reasonable terms, or terms that are acceptable to us. If we are unable to repay amounts owing under the Credit Facility, the lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Dividends

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, among other things, no default, event of default or borrowing base shortfall exists, would reasonably be expected to result from, such declaration or payment.

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

The future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower cash flow from operating activities, which result from lower commodity prices and any decision by us to finance capital expenditures using cash flow from operating activities.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use cash flow from operating activities to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Political Uncertainty

Our results can 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 impact our existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for our activities or restrict the operation of third-party infrastructure that we rely on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact our results.

Other government and political factors that could adversely affect our financial results 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 affect our operations. 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, and the success of these initiatives may decrease demand for our products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt our activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

Changing Investor Sentiment

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our own. 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. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain of our non core assets may realize less on disposition than their carrying value on our financial statements.

Project Risks

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget, or at all.

Operational Dependence

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

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

Hedging

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

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

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

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

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

Royalty Regimes

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local 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. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, 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 us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change

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

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

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 us, for alleged personal injury, property damage, or other potential liabilities. While we are not a party to any such litigation or proceedings, we 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 us, impact our operations and have an adverse impact on our financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts requires our management to dedicate significant time and resources to these climate change-related concerns, may adversely affect our operations, the demand for and price of our securities and may negatively impact our cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our business and ability to attract and retain skilled employees, obtain regulatory permits, licenses, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical risks

Based on our 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 our ability to access our properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to our assets or cause disruptions to the production and transport of our products or the delivery of goods and services in our supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Substantial Capital Requirements

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

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

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

Additional Funding Requirements

Our revenues from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, we may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing Shareholders. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole, or in part, with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Title to and Right to Produce from Assets

Our actual title to and interest in our properties, and our right to produce and sell the oil and natural gas therefrom, may vary from our records. In addition, there may be valid legal challenges or legislative changes that affect our title to and right to produce from our oil and natural gas properties, which could impair our activities and result in a reduction of the revenue received by us.

If a defect exists in the chain of title or in our right to produce, or a legal challenge or legislative change arises, it is possible that we may lose all, or a portion of, the properties to which the title defect relates and/or our right to produce from such properties. This may have a material adverse effect on our business, financial condition, results of operations and prospects.

Reserves Estimates

There are numerous uncertainties inherent in estimating reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form 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 revenue from such estimated reserves are based upon a number of variable factors and assumptions, such as:

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

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

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

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net revenue as summarized herein. Actual future net revenue will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Our insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead us to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, our overall risk exposure could be increased and we could incur significant costs.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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 oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and funds flow by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Dilution

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

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

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

Litigation

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

Indigenous Claims

Opposition by Indigenous groups of the operations, development or exploratory activities of oil and gas companies in any of the jurisdictions in which the Corporation has interests may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on its operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Recently, the government of British Columbia and the First Nations group have come to an agreement relating to further industrial activities in the area, which will have an impact on such industrial activities. The developments in northeastern British Columbia relating to Indigenous rights, may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and us remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

Breach of Confidentiality

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

Russian Ukrainian Conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certification process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

Seasonality

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 may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain of our oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg.

Third Party Credit Risk

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

Conflicts of Interest

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

Information Technology Systems and Cyber-Security

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

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. Although we have a social media policy, we do not restrict the social media access of our employees. Despite these efforts, there are significant risks that the Corporation 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.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. We also employ encryption protection of our confidential information, all computers and other electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our 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. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Expansion into New Activities

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

Disposal of Fluids Used in Operations

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

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with our Operations

Our business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which we operate as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which we have no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and hydrocarbon companies may impact our reputation. See "*Climate Change*" in these Risk Factors.

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

Intellectual Property Litigation

Due to the rapid development of oil and natural gas technology, in the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that we have infringed the intellectual property rights of others or which we initiate against others we believe are infringing upon our intellectual property rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to:

- pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;
- expend significant resources to develop or acquire non-infringing intellectual property;
- discontinue processes incorporating infringing technology; or
- obtain licences to the infringing intellectual property.

However, we may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on our business and financial results.

Forward-Looking Information

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward Looking Information and Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings we are or were a party to, or that any of our property is or was the subject of, during our most recent financial year, nor are any such legal proceedings known to us to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of our current assets.

There are no: (a) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority since our inception; (b) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; and (c) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority since our inception.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described herein, there is no material interest, direct or indirect, of any: (a) director or executive officer; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of our voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction during the previous three years that has materially affected or is reasonably expected to materially affect us.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9. KPMG LLP has been our auditors since inception.

The transfer agent and registrar for the Common Shares is Odyssey Trust Company of Canada at its principal offices in Calgary, Alberta, Vancouver, British Columbia and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that we have entered into prior to the date of this Annual Information Form, which can reasonably be regarded as presently material, are the following:

1. the second amended and restated credit agreement dated August 5, 2020, as amended by a first amending agreement dated December 8, 2020, a second amending agreement dated January 20, 2021, a third amending agreement dated February 18, 2021, a fourth amending agreement dated May 12, 2021, a fifth amending agreement dated June 14, 2021, a sixth amending agreement dated November 26, 2021, a seventh amending agreement effective May 9, 2022, an eighth amending agreement effective August 3, 2022 and a ninth amending agreement effective November 25, 2022; and

2. the Bonus Award incentive Plan.

Copies of these contracts may be viewed on SEDAR at *www.sedar.com*.

EXPERTS

Interests of Experts

GLJ prepared the Report. None of the designated professionals of GLJ have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

KPMG LLP are our auditors. KPMG LLP have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates, except for John A. Brussa, one of our directors, is the Chair and a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com* and on our website at *www.cardinalenergy.ca*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual shareholders meeting to be held on May 12, 2023. Additional financial information is contained in our financial statements for the year ended December 31, 2022, and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Cardinal Energy Ltd.
600, 400 – 3rd Avenue SW
Calgary AB T2P 4H2
Tel: (403) 234-8681
Fax: (403) 234-0603

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

Management of Cardinal Energy Ltd. ("**Cardinal**") is responsible for the preparation and disclosure of information with respect to Cardinal's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated Cardinal's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources 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) "*M. Scott Ratushny*"
M. Scott Ratushny
Chair and Chief Executive Officer

(signed) "*David D. Johnson*"
David D. Johnson
Director and Chair of the Reserves Committee

(signed) "*Shawn Van Spankeren*"
Shawn Van Spankeren
Chief Financial Officer

(signed) "*John Gordon*"
John Gordon
Director and Chair of the Audit Committee

March 17, 2023

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

FORM 51-101F2

To the board of directors of Cardinal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate –M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	Dec. 31, 2022	Canada	-	1,784,376	-	**1,784,376**

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, February 24, 2023.

"Originally Signed By"
Darcy T. Riva, P.Eng.
Manager, Engineering

APPENDIX C

AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Establishment of Committee

The board of directors (the "**Board**") of Cardinal Energy Ltd. ("**Cardinal**" or the "**Corporation**") hereby establishes a committee of the Board to be called the Audit Committee (the "**Committee**").

Role and Objectives

1. The purpose of the Committee is to assist the Board in fulfilling its responsibility for:

   (a) oversight of the nature and scope of the annual audit;

   (b) oversight of the Corporation's management ("**Management**") reporting on internal financial and accounting standards and practices;

   (c) the review of the adequacy of Cardinal's financial information, accounting systems and procedures;

   (d) the review of financial reporting and statements;

   and the Board has charged the Committee with the responsibility of recommending, for Board approval, the interim and annual audited financial statements and other mandatory disclosure releases containing financial information.

2. The primary objectives of the Committee are as follows:

   (a) to assist the directors of the Corporation ("Directors") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Cardinal and related matters;

   (b) to facilitate communication between the Directors and external auditor;

   (c) to strengthen the external auditor's independence;

   (d) to strengthen the credibility and objectivity of Cardinal's financial reports; and

   (e) to facilitate discussions and communication between Directors on the Committee, Management and the external auditor.

Membership of Committee

1. The Committee shall be comprised of at least three (3) Directors or all of whom shall be "independent" (as such term is used in National Instrument 52-110 – *Audit Committees* (as amended from time to time) ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

3. The Board shall have the power to appoint the Committee Chair and other members of the Committee.

Specific Duties and Responsibilities

To carry out its responsibilities, the Committee shall:

1. Oversee the work of the external auditor, including the resolution of any disagreements between Management and the external auditor regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to the integrity of Cardinal's internal control and management information systems by:

   (a) monitoring compliance with legal, ethical and regulatory requirements including the certification process;

   (b) review Cardinal's process for testing its internal controls;

   (c) reviewing the external auditor's (and internal auditor if one is appointed by Cardinal) assessment of the internal controls of Cardinal, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses.

3. Review the annual and interim financial statements of Cardinal and related management's discussion and analysis ("**MD&A**") prior to Board approval and before Cardinal publicly discloses this information. The process should include but not be limited to:

   (a) reviewing the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;

   (b) reviewing significant accruals, reserves or other estimates such as impairment and asset retirement obligations;

   (c) reviewing the accounting treatment of unusual or non-recurring transactions;

   (d) reviewing compliance with covenants under loan agreements;

   (e) reviewing significant or unusual transactions outside of the normal course of business of Cardinal;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditor, whether or not included in the financial statements;

   (h) reviewing unresolved differences or disagreements between Management and the external auditor;

   (i) reviewing Cardinal's risk management policies and procedures including hedging policies, litigation matters, and insurance program;

   (j) reviewing non-recurring transactions;

   (k) reviewing significant or unusual transactions outside of the normal course of business of Cardinal

(l) reviewing related party transactions;

(m) obtaining explanations of significant variances with comparative reporting periods; and

(n) reviewing and approving Cardinal's hiring policies regarding partners, employees and former partners and employees of Cardinal's present and former external auditor.

4. The Committee must review or be satisfied that adequate procedures are in place for the review of Cardinal's public disclosure of financial information extracted or derived from Cardinal's financial statements, including prospectuses, annual information forms and business acquisition reports, other than the public disclosures referred to in subsection (3), prior to their release, and must periodically assess the adequacy of those procedures.

5. With respect to the appointment of external auditor by the Board, the Committee shall:

(a) recommend to the Board the appointment of the external auditor;

(b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditor and confirmation that the external auditor will report directly to the Committee;

(c) on an annual basis, review and discuss with the external auditor all significant relationships such auditors have with Cardinal to determine the auditor independence;

(d) when there is to be a change in auditor, review the issues related to the change and the information to be included in the required notice to securities regulators of such change, if required; and

(e) review and pre-approve any non-audit services to be provided to Cardinal or its subsidiaries by the external auditor and consider the impact on the independence of such auditor.

6. The Committee must pre–approve all non–audit services to be provided to Cardinal or its subsidiaries by the external auditor. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member complies with such other procedures as may be established by the Committee from time to time.

7. The Committee will annually review with the external auditor their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Cardinal and its subsidiaries (if any).

8. The Committee shall establish a procedure for:

(a) the receipt, retention and treatment of complaints received by Cardinal regarding accounting, internal accounting controls or auditing matters; and

(b) the confidential, anonymous submission by employees of Cardinal of concerns regarding questionable accounting or auditing matters.

9. The Committee shall have the authority to investigate any financial activity of Cardinal. All employees of Cardinal are to cooperate as requested by the Committee.

10. The Committee shall meet periodically with the external auditor, independent of Management. The issues for consideration should include, but are not limited to:

(a) obtain feedback on competencies, skill sets and performance of key members of the financial reporting team;

(b) enquire as to significant differences from prior year period audits or reviews;

(c) enquire as to transactions accounted for in an acceptable manner but not a basis which, in the opinion of the external auditor was not the preferable accounting treatment;

(d) enquire as to any differences between Management and the external auditor;

(e) enquire as to material differences in accounting policies, disclosures or presentation from prior periods;

(f) enquire as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditor;

(g) enquire as to any other matters or observations that the external auditor would like to bring to the attention of the Committee.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. Meetings may occur via telephone or teleconference.

4. The time at which and place where the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board.

5. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair may determine. The Chief Financial Officer of Cardinal will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

6. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

7. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of Cardinal and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained.

10. If determined appropriate, following meetings of the Committee, a list of tasks or matters to be followed up upon shall be prepared including the time table for completion thereof and the responsibility for completion, the status of which matter shall be reviewed at the next meeting of the Committee or as otherwise determined by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at such compensation as established by the Committee and at the expense of Cardinal without any further approval of the Board.

12. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

13. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chair of the Board or the Lead Director by the Chair.

Re-approved by the Board of Directors on March 14, 2022.