ANNUAL INFORMATION FORM

For the Year Ended December 31, 2020

Dated March 26, 2021

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.

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 March 2, 2021, evaluating 100% of our crude oil, natural gas and natural gas liquids reserves as at December 31, 2020.

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.

Common Shares means our common shares as presently constituted.

Credit Facility means our $225 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.

Secured Notes means our second lien secured notes, as more particularly described under the heading "*Description of our Capital Structure – Secured Notes*".

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

Warrants means our common share purchase warrants issued on December 30, 2020, each of which entitles 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.

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
ESG	environmental, social and governance
EOR	enhanced oil recovery
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	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	kilometres	1.609
kilometres	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, our 2021 capital budget and plans and our dividend program and plans; "*General Description of Our Business*" as to our business plans, focus, strategies and objectives, production decline rates, drilling inventories, 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 2021 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, optimization and operating cost reduction 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:

- waterflood optimization opportunities and the results therefrom;
- the performance characteristics of our oil and natural gas properties;
- expectations regarding the renewal of our Credit Facility;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- treatment under governmental regulatory regimes and tax laws; and
- the anticipated impact of the factors discussed under the heading "*Industry Conditions*" on us.

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;
- weakness in the oil and natural gas industry;
- market prices of oil and natural gas;
- risks relating to our Credit Facility;
- exploration, development and production risks;
- geological, technical, drilling and processing problems;
- stock market volatility;
- restrictions on our ability to pay dividends and the impact of changes to our dividend policy;
- political or economic developments;
- incorrect assessments of the value of acquisitions;
- our ability to market our oil and natural gas;
- fluctuation in the supply and demand for oil and natural gas;
- changes in general economic, market and business conditions;
- operational risks and liabilities inherent in oil and natural gas operations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- ability to obtain regulatory and other third party approvals;
- water and CO_2 supplies;
- environmental risks;
- climate change risks;
- changes in income tax laws or changes in tax laws, including carbon taxes, and incentive programs relating to the oil and gas industry;
- uncertainties and changes in royalty regimes;
- fluctuations in foreign exchange or interest rates;
- the inability to access sufficient capital from internal and external sources;
- fluctuations in the availability and costs of borrowing;
- our hedging activities
- 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 occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- cyber-security issues; 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, including the documents incorporated by reference herein, 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. **Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

NON-GAAP MEASURES

Throughout this Annual Information Form we use the term "netback" (as defined in the COGE Handbook) which has been calculated by management and does not have a standardized prescribed meaning under generally accepted accounting principles in Canada and may not be comparable with the calculation of similar measurements by other entities. "Netback" is calculated on a Boe basis and is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. We use netback to better analyze the operating performance of our oil and natural gas assets against prior periods.

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. 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 commenced operations in May of 2012 and through a series of acquisitions, we successfully established two core operating areas in Chauvin and Wainwright. In the third quarter of 2013, we completed an acquisition of assets in the Bantry area of Alberta, a new focus area in which we had identified development drilling opportunities. 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.

Since becoming a public company, we have continued to complete accretive and strategic acquisitions to establish our current core areas of Bantry, Wainwright, Mitsue, Grande Prairie/House Mountain and Midale. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Developments in 2018

Effective January 15, 2018, Shawn Van Spankeren was appointed Chief Financial Officer, replacing Doug Smith who retired as our Chief Financial Officer effective January 9, 2018.

On January 12, 2018, we closed a consolidating acquisition increasing our working interest in the Midale Unit from 68.8% to 77.2% for $18.5 million which was funded by $7.3 million in cash and the issuance of 2,314,815 Common Shares.

On March 7, 2018 we completed the sale of various fee title lands, which included proved plus probable royalty interest reserves, in the Weyburn area of Saskatchewan and a new gross overriding royalty on the Mitsue Gilwood Unit for net proceeds of $24 million plus additional working interests in certain producing wells in our Wainwright area.

On April 1, 2018, Ken Younger was appointed Vice President, South and on May 14, 2018, Wes Heatherington was appointed Vice President, North.

On August 30, 2018, we issued 640,000 flow-through Common Shares pursuant to a private placement at $6.25 per Common Share for gross proceeds of $4.0 million.

Between August 30, 2018 and September 5, 2018, we issued an aggregate of 1,024,000 flow-through Common Shares pursuant to a private placement at $5.65 per Common Share for gross proceeds of $5.8 million.

On September 14, 2018, we sold a royalty interest on our Midale properties for gross proceeds of $12.5 million.

On December 6, 2018, we reduced our dividend from $0.035 per Common Share per month to $0.01 per Common Share per month effective for the December 2018 dividend payable in January 2019. See "*Dividend Policy*".

On December 27, 2018, we announced that the Toronto Stock Exchange had accepted notice of our intention to commence a normal course issuer bid to allow us to purchase up to $5 million aggregate principal amount of our 5.50% Debentures over a period of 12 months commencing on December 19, 2018. We repurchased and cancelled the maximum amount of 5.50% Debentures permitted at an average rate of $96.9314 per $100 principal amount.

Developments in 2019

On February 28, 2019 our Board of Directors approved a capital expenditure budget for 2019 that focused on long-term operating cost reduction initiatives, debt repayment and maintaining our production volumes at 2018 levels.

On April 12, 2019, we announced an increase to our dividend from $0.01 per Common Share per month to $0.015 per Common Share per month effective for the July 2019 dividend payable in August 2019. See "*Dividend Policy*".

On July 30, 2019, we announced that our Credit Facility would remain unchanged at $325 million and that the term had been extended for another year.

On July 30, 2019, we announced that the Toronto Stock Exchange accepted notice of our intention to commence a normal course issuer bid for our Common Shares ("**Share NCIB**"). The Share NCIB allowed us to purchase up to 11,128,148 Common Shares (representing approximately 10% of the then issued and outstanding Common Shares) over a period of 12 months commencing on August 2, 2019. In aggregate, we purchased 2,570,246 Common Shares pursuant to the Share NCIB at an average price of $2.46. The Share NCIB expired in August 2020.

On November 7, 2019, we announced that we had recently commenced a multi-well drilling program to fulfill farm-in commitments and take advantage of additional drilling opportunities and had therefore increased our 2019 capital budget from $52 million to $62 million.

On December 9, 2019, we announced that our Board of Directors had approved an operating and capital budget for 2020 of $63 to $69 million focused on debt reduction, dividend payments, operating cost reductions, increasing production volumes and reducing our environmental footprint through asset retirement expenditures. We also announced that the Toronto Stock Exchange had accepted notice of our intention to commence a normal course issuer bid (the "**Second Debenture NCIB**") to purchase up to $4.45 million aggregate principal amount of our 5.50% Debentures over a twelve month period. The Second Debenture NCIB expired on December 19, 2020. We repurchased and cancelled $0.5 million principal amount of the 5.50% Debentures pursuant to the Second Debenture NCIB at an average rate of $31.072 per $100 principal amount.

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. For further information on our Credit Facility, see "*Description of our Capital Structure – Credit Facility*".

On June 19, 2020, we received Debentureholder approval for certain amendments to the 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 Shares and a maturity date of December 31, 2022.

On December 30, 2020, we closed a non-brokered private placement of approximately $16.9 million principal amount of Secured Notes which were issued at a 4% discount for net proceeds of $16.2 million. 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 Warrant. The proceeds from the private placement were used to fund the repayment of the 5.50% Debentures 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 Secured Notes and 1,875,000 Units. Further particulars regarding insider participation in the private placement is set forth in our material change report dated December 15, 2020, a copy of which gas been filed on our SEDAR profile at *www.sedar.com*.

Recent Developments

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 does not contemplate drilling any new wells and we will 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, 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 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 March 11, 2021, $28.0 million of principal amount of the 8.00% Debentures representing approximately 99.3% of the outstanding 8.00% Debentures, voluntarily converted their 8.00% Debentures 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.

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.

We commenced operations in May of 2012. Since then, we have acquired several low decline crude oil properties. These acquisitions have provided us with a solid base of low decline oil and natural gas production, along with a large multi-year drilling inventory. The acquisitions included extensive operating infrastructure and are located on all season access lands primarily in the Bantry, Mitsue, Wainwright, Grande Prairie/House Mountain areas of Alberta and Midale area of Saskatchewan. See "*Statement of Oil and Gas Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

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*".

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, 2020, we had 54 full-time employees located at our head office and 104 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.

We develop emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. 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 occupational health 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 2020 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. Our direct operations sequester more $C0_2$ than our operations emit (1.34 tonnes of $C0_2$ equivalent sequestered for every tonne of $C0_2$ equivalent emissions in 2020) making us unique among oil and gas producers. We continue to execute projects to enhance our ESG progress, and we look forward to providing updated ESG reporting in the future.

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 March 2, 2021. The statement is effective as of December 31, 2020. 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, 2020 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, 2020 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)

	SUMMARY OF OIL AND NATURAL GAS RESERVES AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	36,186	31,683	18,934	16,697	37,531	33,863	2,984	2,363
Developed Non-Producing	1,371	1,262	1,011	923	6,901	6,187	179	148
Undeveloped	4,512	4,076	1,845	1,556	2,531	2,192	226	211
TOTAL PROVED	42,069	37,020	21,790	19,176	46,963	42,242	3,389	2,721
TOTAL PROBABLE	14,180	12,288	6,351	5,421	15,457	13,913	1,076	912
TOTAL PROVED PLUS PROBABLE	56,249	49,308	28,141	24,597	62,420	56,155	4,465	3,633

Note:

(1) Includes solution gas.

	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2020 BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/ YEAR
RESERVES CATEGORY	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)	$/Boe (1)
PROVED:						
Developed Producing	950	771	600	488	413	10.64
Developed Non-Producing (2)	(130)	(44)	(22)	(14)	(10)	(6.49)
Undeveloped	142	79	50	32	21	8.00
TOTAL PROVED	963	806	628	507	424	9.52
TOTAL PROBABLE	692	312	183	124	90	8.75
TOTAL PROVED PLUS PROBABLE	1,655	1,118	811	631	514	9.34

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, 2020 AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
PROVED:					
Developed Producing	950	771	600	488	413
Developed Non-Producing	(130)	(44)	(22)	(14)	(10)
Undeveloped	142	79	50	32	21
TOTAL PROVED	963	806	628	507	424
TOTAL PROBABLE	555	262	161	113	84
TOTAL PROVED PLUS PROBABLE	1,518	1,067	789	620	509

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2020
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	4,449	601	2,140	173	573	963	0	963
TOTAL PROVED PLUS PROBABLE	6,193	867	2,876	219	576	1,655	137	1,518

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, 2020 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]	462	10.94
Heavy Crude Oil [3]	146	7.41
Conventional Natural Gas [4]	20	4.97
	628	9.52
TOTAL PROVED PLUS PROBABLE		
Light and Medium Crude Oil [3]	593	10.53
Heavy Crude Oil [3]	195	7.66
Conventional Natural Gas [4]	24	4.60
	811	9.34

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, 2021. 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, 2020

	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									
2021	47.17	55.76	44.63	53.89	2.78	18.18	26.36	0.0	0.7683
2022	50.17	59.89	48.18	57.58	2.70	21.91	32.85	1.3	0.7650
2023	53.17	63.48	52.10	61.05	2.61	24.57	39.20	2.0	0.7633
2024	54.97	65.76	54.10	63.25	2.65	25.47	40.65	2.0	0.7633
2025	56.07	67.13	55.19	64.57	2.70	26.00	41.50	2.0	0.7633
2026	57.19	68.53	56.29	65.91	2.76	26.54	42.36	2.0	0.7633
2027	58.34	69.95	57.42	67.28	2.81	27.09	43.24	2.0	0.7633
2028	59.50	71.40	58.57	68.68	2.86	27.65	44.14	2.0	0.7633
2029	60.69	72.88	59.74	70.10	2.92	28.23	45.06	2.0	0.7633
2030	61.91	74.34	60.93	71.51	2.98	28.79	45.96	2.0	0.7633
2031	63.15	75.83	62.15	72.93	3.04	29.37	46.88	2.0	0.7633
2032	64.41	77.34	63.39	74.40	3.10	29.96	47.82	2.0	0.7633
2033	65.70	78.89	64.66	75.89	3.16	30.55	48.78	2.0	0.7633
2034	67.01	80.47	65.95	77.40	3.23	31.16	49.75	2.0	0.7633
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.7633

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, 2020, excluding price risk management activities, were $38.67/Bbl for light and medium crude oil, $34.58/Bbl for heavy crude oil, $1.67/Mcf for natural gas and $17.63/Bbl for NGLs.

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2020, 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, 2019	**43,962**	**14,317**	**58,279**	**26,864**	**8,023**	**34,887**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [1]	621	87	707	346	(346)	-
Technical Revisions [2]	4,792	406	5,199	(772)	(1,921)	(2,693)
Acquisitions [3]	-	-	-	-	-	-
Dispositions[3]	(113)	(30)	(143)	-	-	-
Economic Factors [4]	(3,387)	(600)	(3,987)	(2,882)	596	(2,286)
Production	(3,805)	-	(3,805)	(1,766)	-	(1,766)
December 31, 2020	**42,069**	**14,180**	**56,249**	**21,790**	**6,351**	**28,141**

	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, 2019	**46,704**	**16,312**	**63,016**	**3,276**	**1,079**	**4,355**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [1]	3,099	446	3,545	24	3	27
Technical Revisions [2]	5,629	(455)	5,174	616	56	673
Acquisitions [3]	-	-	-	-	-	-
Dispositions [3]	(7)	(2)	(9)	(2)	-	(2)
Economic Factors [4]	(3,452)	(844)	(4,297)	(211)	(62)	(273)
Production	(5,009)	-	(5,009)	(315)	-	(315)
December 31, 2020	**46,963**	**15,457**	**62,420**	**3,389**	**1,076**	**4,465**

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 2020, these revisions were: (i) positive light and medium crude oil revisions in the Midale, and House Mountain areas; (ii) negative heavy crude oil reserves revisions in the Wainwright and Jenner areas; and (iii) positive natural gas reserve revisions due to reactivations and higher solution gas recovery.
(3) There were no reserves acquisitions in 2020 and only minor reserves dispositions.
(4) The economic factors amount is the change in reserves due to changes in product pricing.

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
2018	1,388	3,443	1,494	2,880	1,195	3,453	22	129
2019	1,785	4,941	174	2,840	505	3,249	150	260
2020	233	4,518	-	1,845	419	2,531	3	226

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 7 MMBoe of proved undeveloped reserves in the Report with $108 million of associated undiscounted capital, of which $40 million is forecast to be spent in the first two years. A total of $94 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
2018	1,318	2,388	583	1,902	486	2,341	9	75
2019	1,060	3,514	968	2,667	738	2,517	94	157
2020	34	3,750	-	1,629	61	1,906	-	140

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 $40 million of associated undiscounted capital, of which $37 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 $568 million undiscounted (and inflated by two percent) and $80 million discounted (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 revenues disclosed in this Annual Information Form. An additional $7 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)
2021	9	10
2022	44	53
2023	35	48
2024	31	48
2025	15	15
Remaining	39	45
Total (Undiscounted)	173	219
Discounted (10%)	120	152

Note:

(1) Includes $39 million and $46 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.

At the time of the preparation of the Report, our 2021 capital budget was $25 to $30 million. 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, 2020. Information in respect of current production is average production, net to our working interest, except where otherwise indicated. We operate approximately 95% 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.**

Bantry, Alberta

Bantry, which includes the Alderson, Duchess, Rosemary, Kinnivie and Jenner areas, is located near Brooks, Alberta. Bantry's average 2020 production was approximately 4,916 Boe/d (60% light and medium crude oil, 21% heavy oil, 17% conventional natural gas and 2% NGL). The majority of our oil in this area is pipeline connected to Cardinal-operated facilities, and a 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 highlands to the south 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 the producing oil reservoirs on the lands are under enhanced recovery in the form of waterflood. We have identified areas where we can optimize existing waterfloods to further enhance oil recoveries.

In 2020, we continued our successful drilling program in Bantry, drilling six (6.0 net) Glauconitic horizontal wells and one (1.0 net) multi-leg Ellerslie horizontal well. At this point, we do not plan to drill any additional wells in 2021. See "*General Development of Our Business – History and Development – Recent Developments*".

Mitsue, Alberta

Our Mitsue property is located approximately 280 kilometres north of Edmonton, Alberta. Average 2020 production for this property was 2,240 Boe/d (74% light and medium crude oil, 6% NGL and 20% 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 a main oil battery 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 from the Gilwood sandstone of the Middle Devonian Watt Mountain formation. At 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.

House Mountain, Alberta

House Mountain is located approximately 50 kilometres from our Mitsue field and approximately 280 kilometres north of Edmonton. The property includes an average 70% 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 updip 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 water cut from the pool is approximately 70%. 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 1,950 Boe/d (91% light and medium crude oil and 9% NGL) during 2020.

Grande Prairie, Alberta

Located to the west of the City of Grande Prairie, this property produced 1,954 Boe/d (27% light and medium crude oil, 27% NGL and 53% conventional natural gas), primarily from the Cretaceous-aged sandstones of the Dunvegan and Falher formations. Multiple infill drilling and extension opportunities are planned over the next several years at our Knopcik Dunvegan oil development.

The majority of our production here is pipeline-connected and operated, however natural gas is generally processed through third party facilities.

We did not drill any wells in this area during 2020 and currently do not have any plans to drill any wells in 2021.

Wainwright, Alberta

Wainwright is located 195 kilometres southeast of Edmonton, Alberta. In 2020, the Wainwright properties (including the Chauvin, Forestburg and Hayter areas) produced approximately 4,214 Boe/d (8% light and medium crude oil, 91% heavy oil and 1% conventional natural gas). Crude oil makes up 99% of the total reserves and production in this area and 94% of the total proved and probable reserves assigned to this area are producing. The base production in Wainwright has a low production decline of approximately 5% 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 Waseca sandstone 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.

Midale, Saskatchewan

The Midale property is located in southeast Saskatchewan approximately 150 kilometres 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 non-unit Midale, 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 (below 5%) and both units have significant development drilling upside. Our average 2020 production from these properties was 3,169 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 water flood, 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 in to the reservoir.

We currently do not plan to drill any wells in this area in 2021.

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, 2020.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING		PRODUCING		NON-PRODUCING	
	Gross	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,697	1,408	1,221	899	149	88	242	161
Saskatchewan	809	176	393	88	-	-	-	-
Total	2,506	1,584	1,614	988	149	88	242	161

Note:

(1) Does not include 1,628 gross (1,032 net) service wells.

Of the non-producing wells, 111 gross (90 net) were capable of production and had reserves assigned to them. As of the date of this Annual Information Form 55 gross (44 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, 2020.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	172,872	101,330	471,854	320,716	644,726	422,046
Saskatchewan	19,840	14,458	30,795	25,579	50,636	40,037
Total	192,712	115,788	502,649	346,295	695,362	462,083

Notes:

(1) Rights to explore, develop and exploit 7,026 net acres of our land holdings could expire by December 31, 2021 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, 2020 we held 400,405 gross acres (223,344 net acres) to which no reserves are currently attributed, all of which are located in Canada. Rights to explore, develop and exploit 1,586 net acres of these land holdings could expire by December 31, 2021 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 implemented a hedging policy using, amongst others, collars, puts and fixed price swaps which allows us to hedge our gross oil, NGL 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*".

For further information, see note 18 to our financial statements for the year ended December 31, 2020.

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, 2020.

EXPENDITURE	YEAR ENDED DECEMBER 31, 2020 ($000S)
Property acquisition costs – Unproved properties (1)	470
Property acquisition costs – Proved properties	-
Exploration costs (2)	-
Development costs (3)	29,923
Total	30,393

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, 2020.

	DEVELOPMENT		EXPLORATORY(1)	
	GROSS	NET	GROSS	NET
Conventional Natural Gas	-	-	-	-
Light and Medium Crude Oil	7	7.0	-	-
Dry	-	-	-	-
Service	-	-	-	-
Total	7	7.0	-	-

We currently do not plan to drill any additional wells in 2021. See "*General Development of Our Business – History and Development – Recent Developments*".

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2020, 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	9,683	4,582	14,919	906	17,657
Probable	165	84	205	15	299
Proved plus Probable	9,848	4,665	15,124	922	17,956

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, 2020.

	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)	2,936	1,055	75	5,098	4,916
Grande Prairie	520	-	520	5,484	1,954
House Mountain	1,779	-	170	-	1,950
Mitsue	1,648	-	144	2,681	2,240
Wainwright (2)	387	3,771	2	322	4,214
Midale, SK	3,170	-	-	-	3,169
Total	10,440	4,826	911	13,585	18,442

Notes:

(1) Includes the Alderson, Duchess, Rosemary, Kinnivie and Jenner areas.
(2) Includes the Chauvin, Forestburg and Hayter 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 2020				YEAR ENDED
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	DEC. 31, 2020
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	11,633	10,002	9,958	10,171	10,439
Heavy Crude Oil (Bbls/d)	5,459	4,249	4,624	4,978	4,827
Natural Gas Liquids (Bbls/d)	836	772	834	1,200	911
Conventional Natural Gas (Mcf/d)	14,368	12,873	13,448	13,653	13,585
Combined (Boe/d)	20,323	17,169	17,657	18,625	18,442
Average Prices Received					
Light and Medium Crude Oil ($/Bbl)	42.01	22.73	44.73	44.45	38.67
Heavy Crude Oil ($/Bbl)	31.15	22.56	41.63	41.90	34.58
Natural Gas Liquids ($/Bbl)	21.35	11.96	17.46	18.78	17.63
Conventional Natural Gas ($/Mcf)	1.45	1.24	1.58	2.49	1.70
Combined ($/Boe)	34.32	20.30	38.16	38.56	33.07
Royalties					
Light and Medium Crude Oil ($/Bbl)	7.68	2.66	6.27	7.09	5.94
Heavy Crude Oil ($/Bbl)	4.12	3.71	6.62	6.44	5.37
Natural Gas Liquids ($/Bbl)	0.75	1.15	1.78	2.19	1.60
Conventional Natural Gas ($/Mcf)	0.03	0.10	0.09	0.23	0.11
Combined ($/Boe)	5.56	2.59	5.42	5.90	4.93
Operating Costs [2][3]					
Light and Medium Crude Oil ($/Bbl)	23.89	17.23	19.38	19.86	20.19
Heavy Crude Oil ($/Bbl)	22.77	16.56	19.09	19.19	19.69
Natural Gas Liquids ($/Bbl)	7.05	5.89	6.66	5.69	6.25
Conventional Natural Gas ($/Mcf)	0.71	0.57	0.74	0.71	0.68
Combined ($/Boe)	20.58	14.81	16.82	16.84	17.39
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.06	0.08	0.31	0.03	0.12
Heavy Crude Oil ($/Bbl)	0.54	0.18	0.21	0.24	0.30
Natural Gas Liquids ($/Bbl)	1.09	0.99	0.90	0.93	0.97
Conventional Natural Gas ($/Mcf)	0.12	0.12	0.11	0.12	0.12
Combined ($/Boe)	0.31	0.24	0.34	0.25	0.29
Netback Received					
Light and Medium Crude Oil ($/Bbl)	10.38	2.76	18.77	17.47	12.42
Heavy Crude Oil ($/Bbl)	3.72	2.11	15.71	16.03	9.22
Natural Gas Liquids ($/Bbl)	12.46	3.91	8.12	9.97	8.80
Conventional Natural Gas ($/Mcf)	0.59	0.46	0.65	1.33	0.76
Combined ($/Boe)	7.87	2.66	15.58	15.57	10.46

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.

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 $225 million is comprised of a $205 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, 2021 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, 2022. 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.

Advances under the Credit Facility are available by way of either prime rate loans, which bear interest at the banks' prime lending rate plus 2.0 to 5.5%, and bankers' acceptances, which are subject to fees and margins ranging from 3.0 to 6.5%. 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*".

Secured Notes

On December 30, 2020, we issued approximately $16.9 million principal amount of Secured Notes at a 4% discount for net proceeds of $16.2 million. The Secured Notes bear interest at 12% per annum, with interest accrued semi-annually and added to the principal amount outstanding and payable on maturity. The Secured Notes mature on June 30, 2022, and contain an extension provision, exercisable by either us or the holders on 30 days' prior written notice, to extend the maturity date to November 30, 2022. The Secured Notes have a second lien on all of our assets and include debt incurrence restrictions.

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.

PERIOD	HIGH	LOW	VOLUME
2020			
January	2.91	2.30	9,728,755
February	2.47	1.77	8,076,701
March	1.99	0.30	20,024,547
April	0.66	0.36	11,928,907
May	0.58	0.43	9,433,652
June	0.85	0.46	16,610,012
July	0.59	0.47	4,571,912
August	0.62	0.50	4,962,154
September	0.61	0.42	2,299,118
October	0.45	0.39	2,760,196
November	0.66	0.37	6,273,984
December	1.08	0.59	12,205,481
2021			
January	1.10	0.81	10,152,369
February	1.79	1.02	25,658,863
March (to March 26)	2.60	1.54	34,760,754

Prior Sales

During the year ended December 31, 2020 we granted a total of 2.6 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, 2020. See note 15 of our annual financial statements for the year ended December 31, 2020 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 Chairman	Our Chairman and Chief Executive Officer since July 6, 2012. Prior thereto, Chairman 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 Chairman of Burnet, Duckworth & Palmer LLP.	July 2012
David D. Johnson (1)(2)(3)(4)(5) Alberta, Canada	Director	Independent Businessperson. Mr. Johnson was the Chairman of Progress Energy Resources Corp., a public oil and gas company, prior to its sale on December 12, 2012.	July 2012
Gregory T. Tisdale (1)(2)(5)(6) Alberta, Canada	Director	Mr. Tisdale is currently a director and founder of Enercapita Energy Ltd., a private junior oil and gas company. Prior thereto he was the Chief Financial Officer of Crescent Point Energy Ltd., a public oil and gas company.	January 2014
Dale Orton Alberta, Canada	Chief Operating Officer	Our Chief Operating Office 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
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

NAME, PROVINCE AND COUNTRY OF RESIDENCE	POSITION HELD	PRINCIPAL OCCUPATION FOR THE LAST FIVE YEARS	DIRECTOR SINCE
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. Prior thereto, Production Manager with Glencoe Resources Ltd. since August 2010.	N/A

Notes:

(1) Member of our Audit Committee. Mr. Greg Tisdale 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 D. 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.
(6) Mr. Tisdale is not standing for re-election at this year's shareholders meeting.

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, Ratushny and Tisdale 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, Ratushny and Tisdale 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.

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 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 Greg Tisdale (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*. Mr. Tisdale is not standing for re-election at this year's shareholders meeting and the Audit Committee will be re-constituted following the meeting.

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.

Greg Tisdale:

Mr. Tisdale is a founder and current CEO of Enercapita, a position held since inception of the Company in 2014. Prior to Enercapita, he was the Chief Financial Officer of Crescent Point Energy, a position he held for twelve years and was part of the executive team that grew from a junior oil and gas company to one of the largest independent oil companies in North America. Mr. Tisdale has over 25 years experience in the energy industry working with several respected companies including Crescent Point, Direct Energy, AltaGas Services and Shell Trading. In addition, he has been a past Director of several public and non for profit entities. Mr. Tisdale is a Chartered Accountant and holds a Bachelor of Commerce degree (with distinction) from the University of Alberta.

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) ($)	ALL OTHER FEES (4) ($)
2019	185,000	60,000	5,490	25,000
2020	185,000	57,000	2,675	15,000

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 includes additional work required to implement new accounting standards.

DIVIDEND POLICY

We started paying dividends on our Common Shares in 2014.

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.

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 current economic environment. See "*General Development of our Business – Recent Developments".*

At this time, our current Credit Facility restricts our ability to pay dividends without lender approval. In addition, the payment of dividends by us is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

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 – Present	Suspended

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

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 and Saskatchewan 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.

Since early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a significant impact on the price of oil. In an effort to stabilize global oil markets, the Organization of the Petroleum Exporting Countries ("**OPEC**") and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million Bbls/d in April 2020. This agreement contributed to rebalancing global oil markets. However, economic recovery has slowed in some respects due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

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.

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 its production outside of Canada.

One major constraint to the export of oil, natural gas and NGLs is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other 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 over the last several years.

Transportation Constraints and Market Access

Under the Canadian Constitution, 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.

Oil Pipelines

Specific Pipeline Updates

The Enbridge Inc. ("**Enbridge**") Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

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 and it is expected to be in-service in December 2022.

On March 31, 2020, TC Energy Corporation ("**TC Energy**") announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility. While construction on the Keystone XL Pipeline started in April 2020, the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021 that permits the Keystone XL Pipeline to operate across the international border.

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, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the Unites States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge 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.

Marine Tankers

The *Oil Tanker Moratorium Act*, 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 being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced in November 2020. The speed limits and other requirements established in this order will remain in place until permanent rule changes are approved.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge intends to implement include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. If the service change is approved, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

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 in the last several years has generally been depressed relative to other 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. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage (the "**Temporary Service Protocol**"). The change stabilized supply and pricing, particularly during periods of maintenance on the system, but, in February 2021, the CER refused a request to extend the Temporary Service Protocol. However, in October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by 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 late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. 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.

In addition to LNG Canada and the CGL Pipeline projects, the following is an update on various other LNG Projects that have been proposed in Canada:

- In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited. However, both partners are looking to sell some or all of their interest in the project.

- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The British Columbia Oil and Gas Commission (the "**BC Commission**") approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.

- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.

- Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae has delayed its final investment decision until mid-2021.

- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Curtailment

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial crude oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators that are subject to curtailment orders.

As of December 2020, monthly oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose future production limits if needed.

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, 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 have an impact on Western Canada's oil and gas industry at large, including our 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.

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 governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases 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. Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995*. In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"); however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019 and further regulations are currently being developed. Although we have operations on Indian reserve lands, there is no material impact to our activities.

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 NGL 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.

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, 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.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

In 2020, we received government grants through the Canada Emergency Wage Subsidy (“**CEWS**”) and Canada Emergency Rent Subsidy (“**CERS**”) of $4.6 million. We also benefited from the Alberta Governments Site Rehabilitation Program (“**SRP**”) and Saskatchewan Governments Accelerated Site Closure Program (“**ASCP**”) resulting in a reduction in the decommissioning obligation liability of $4.6 million. The SRP and ASCP programs are detailed further below in the "*Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs"* section of these Industry Conditions.

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. The *Mines and Minerals Act* was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

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 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.

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.

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%. 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 $1.50 per acre 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 greenhouse gas ("**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.

On August 28, 2019, the *Impact Assessment Act* (the "**IAA**") replaced the *Canadian Environmental Assessment Act, 2012*.

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. 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 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 right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

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 Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

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

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

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, 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 not have operations in any of these regions.

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 partner in the Petrinex Database.

Liability Management Rating Programs

Alberta

The AER administers a Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"); however, specific details concerning this new program remain forthcoming. The AB LMR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LFP**"), and the Licensee Liability Rating Program (the "**AB LLR Program**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating.

Complementing 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 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 LFP. 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.

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, the AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that they can meet their abandonment and reclamation obligations, such as by posting security or reducing their existing obligations.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a 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 will come into force on proclamation.

Additionally, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF 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.

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"). The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, our ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. We are participating in the voluntary ABC program.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund 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. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements.

In 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. In particular, the proposed changes will include the introduction of new regulations called The Financial Security and Site Closure Regulations (the "**Proposed Closure Regulations**"). While still in the consultation process, the Ministry has explained that the Proposed Closure Regulations are intended to: (i) create a new system for reducing liabilities through prescribed annual reduction targets; (ii) adjust the SK LLR Program to better reflect a licensee's actual assets and liabilities in order to more accurately calculate security deposits; and (iii) introduce a means to determine additional security requirements for transactions that involve a high percentage of inactive assets.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the SRP. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, $400 million in federal funding will be allocated through the ASCP. The first two phases of the ASCP will make $300 million available to eligible service companies to conduct abandonment and reclamation work. A further tranche of the ASCP, up to $100 million, will be made available in the future.

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 revenues.

Federal

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 regulatory 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. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne of CO2e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022, such that, 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. Starting April 1, 2021, the minimum price permissible under the GGPPA is $40/tonne of CO2e. In addition, on March 5, 2021, the federal government introduced for comment the *Greenhouse Gas Offset Credit System Regulations (Canada)* (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are expected to be put in place before the end of 2021.

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.

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a $750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50% for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details will be announced as they are developed.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making.

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.

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta will increase from $30/tonne of CO2e to $40/tonne of CO2e on April 1, 2021. 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 and replaces the previous *Carbon Competitiveness Incentives 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 and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these Directives will support Alberta in achieving its 2025 goal. 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.

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 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program.

On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to 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 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

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.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and 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 December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and Bill C-15 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.

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.

Impact of Pandemics

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on the Corporation's results, business, financial condition or liquidity.

On March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID-19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on our results, business, financial condition or liquidity, for a substantial period of time.

Our business, financial condition, results of operations, revenues, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced revenues resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- crude oil storage constraints resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;

- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

The COVID-19 pandemic has also created additional operational risks for us, including the need to provide enhanced safety measures for our employees; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behaviour; and protect the integrity and functionality of our systems, networks, and data as a larger number of employees work remotely. We are also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of our employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact our results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

Weakness and Volatility in the Oil and Natural Gas Industry

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

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

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 crude 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 are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The 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 our 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 Marketing*" and "*Weakness and Volatility in the Oil and Natural Gas Industry"* in these Risk Factors*.*

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

Our reserves as at December 31, 2020 are estimated using forecast pricing escalating prices as set forth under "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Pricing Assumptions*". These prices are above current forward oil and natural gas prices. If oil and gas prices stay at current levels our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics**.**

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*" and "*Description of our Capital Structure – Secured Notes*".

Our lenders use our reserves, commodity prices, applicable discount rate and other factors to periodically determine our borrowing base. Although commodity prices have improved recently, they continue to be depressed and have fallen dramatically since 2014, and while prices remain volatile as a result of various factors including COVID 19, limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed 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.

The Supreme Court of Canada's decision in Redwater has given rise to new covenants and restrictions under our Credit Facility, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. We are required to provide additional reporting to our lenders regarding our existing and/or budgeted abandonment and reclamation obligations, decommissioning expenses, LMR and/or any material notices or orders received from an energy regulator in any applicable province**.** Our lenders may also be permitted to re-determine our borrowing base following a decline in our LMR below a certain threshold. If we become subject to an abandonment and reclamation order and our estimated cost of compliance with such order exceeds a certain threshold, we must remain compliant with such notice to avoid an event of default under our Credit Facility. See also "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

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.

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 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.

Market Price of our Common Shares

The trading price of 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, including governmental regulatory actions or adverse changes in general market conditions or economic trends. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our 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.

Dividends

We are currently not permitted to pay dividends under our Credit Facility without the prior approval of the lenders within our banking syndicate.

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 w are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

In addition, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") was ratified on July 1, 2020 and may impact our business. See "*Industry Conditions – The North American Trade Agreement and Other Trade Agreements*".

The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration, and has taken action to cancel TC Energy Corporation's Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including us.

In addition to the changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

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 United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where we are active. See "*Industry Conditions – Transportation Constraints and Market Access*".

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

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 – Transportation Constraints and Market Access – Natural Gas*".

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 state of the market for such non-core assets, we may realize less on a disposition than their carrying value on our financial statements.

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.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by 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 and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, legal challenges to Cabinet's approval of the Trans Mountain Pipeline expansion were dismissed, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in our inability to realize the full economic potential of our products or in a reduction of the price offered for our production. Unexpected shut downs 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. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward.

In August 2019, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force, resulting in changes to the federal regulation and associated environmental assessments of major projects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

In January 2021, U.S President Biden took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on us.

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.

Pipeline Systems

The interruption of firm pipeline transportation has and may continue to affect the oil and natural gas industry and limit the ability to fully produce and market oil and natural gas production. In addition, the pro-rationing of capacity on interprovincial pipeline systems may also affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators may also affect our production, operations and financial results. Our production could be adversely impacted by both firm and interruptible transportation service curtailments on TransCanada's NGTL and Canadian Mainline systems.

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

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 market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the 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;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

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 market conditions, 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 Rating Program*" and "*Third Party Credit Risk*" in these Risk Factors.

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.

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 crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". See "*Industry Conditions – Curtailment"* and "*Liability Management*" in these Risk Factors.

In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our 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 Rating Programs*".

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*".

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.

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 – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, 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.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the "Liability Management Framework" (the **"AB LMF"**). Other changes to the requirements of liability management programs may result in significant increases to our compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater* on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. As a result of the decision, the Government of Alberta implemented the *Liabilities Management Statutes and Amendment Act*, which places the financial burden of a defunct licensee's abandonment and reclamation obligations on the working interest partners of the defunct Licensee and may order the AER's Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

In addition, the AB LMF Program may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Seasonality and Extreme Weather Conditions*" in these Risk Factors. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require us to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to our premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, we may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the hydrocarbon industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate-related harms. See "*Non-Governmental Organizations and Eco and Eco-Terrorism Risks*" and "*Reputational Risk Associated with our Operations*" in these Risk Factors.

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

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests and rivers and a wildfire or flood could lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. While several provinces challenged the constitutionality of federal regime, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

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 cash generated 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.

See "*Industry Conditions – Royalties and Incentives*"

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 future net revenue from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. 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.

Availability and Cost of Material and Equipment

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

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 document 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 revenues from such estimated reserves are based upon a number of variable factors and assumptions, such as:

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

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

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

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

Actual production and future net revenue derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated future net revenues 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.

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 cash flow from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Dilution

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

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

Litigation

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

Indigenous Claims

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

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.

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*".

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.

Information Technology Systems and Cyber-Security

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware. The ongoing COVID-19 pandemic has increased cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conduct annual cyber-security risk assessments. We have also implemented new information technology processes applicable to employees who are working remotely during the COVID-19 pandemic. 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 on our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Expansion into New Activities

The operations and expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in 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. See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with our Operations

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

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

Social Media

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

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 effective December 8, 2020, a second amending agreement effective January 20, 2021 and a third amending agreement effective February 18, 2021; 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 Chairman 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 14, 2021. Additional financial information is contained in our financial statements for the year ended December 31, 2020 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
Chairman 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) "*Gregory T. Tisdale*"
Gregory T. Tisdale
Director and Chair of the Audit Committee

March 2, 2021

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, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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, 2020, 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 – $000s)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2020	Canada	-	**811,335**	-	**811,335**

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 March 2, 2021.

"Originally Signed By"

Todd J. Ikeda, P. Eng
Vice-President

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 16, 2021.