ANNUAL INFORMATION FORM

For the Year Ended December 31, 2019

Dated March 20, 2020

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 Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

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

Report means the report prepared by GLJ dated February 26, 2020, evaluating 100% of our crude oil, natural gas and natural gas liquids reserves as at December 31, 2019.

Securities and Other terms

Common Shares means our common shares as presently constituted.

Computershare means Computershare Trust Company of Canada.

Credit Facility means our $325 million syndicated credit facility, as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Current Market Price is defined in the Indenture to mean, on any day, the volume weighted average trading price of the Common Shares on the Toronto Stock Exchange (or such other recognized stock exchange) for the 20 consecutive trading days ending on the fifth trading day preceding such date.

Debentures means our 5.50% extendible convertible unsecured subordinated debentures, as more particularly described under the heading "*Description of our Capital Structure – Debentures*".

Indenture means the indenture between us and Computershare under which the Debentures were issued.

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

ABBREVIATIONS

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

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
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
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 2020 capital budget and plans, anticipated 2020 production and capital spending required to maintain this level of production, 2020 exit debt levels, 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 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 2020 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;
- expectations regarding the repayment of our Debentures;
- the impact of global health concerns, such as COVID-19;
- 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:

- exploration, development and production risks and liabilities inherent in oil and natural gas operations;
- risks associated with the weakness in the oil and gas industry;
- our ability to market our oil and natural gas;
- market prices and supply and demand for oil and natural gas;
- risks associated with our Debentures and our Credit Facility;
- stock market volatility;
- the impact of COVID-19 crisis;
- incorrect assessments of the value of acquisitions and a failure and failure to realize the benefits or acquisitions;
- lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines;
- changes to our dividend policy;
- political or economic developments;
- political uncertainty and changes in general economic, market and business conditions;
- changing investor sentiment;
- project risks;
- operational dependence;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- changes to governmental controls and regulations;
- geological, technical, drilling and processing problems;
- environmental risks;
- climate change policies and regulation;
- volatility of foreign exchange and interest rates;
- an inability to access sufficient capital from internal and external sources;
- fluctuations in the availability of and costs of borrowing;
- our hedging activities;
- uncertainties associated with estimating crude oil and natural gas reserves;
- the accuracy of crude oil and natural gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- uncertainties in regard to the timing of our exploration and development program;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws, carbon taxes or changes in tax laws and incentive programs relating to the oil and gas industry;
- Information technology and 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

This Annual Information Form contains certain oil and gas metrics, prepared by management, such as finding development and acquisition costs which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this Annual Information Form to provide readers with additional measures to evaluate the performance of our oil and gas activities however, such measures are not reliable indicators of our future performance and future performance may not compare to our performance in previous periods and therefore such metrics should not be unduly relied upon.

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 my 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 material 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 2017

On March 17, 2017, we closed an acquisition of assets within our Grande Prairie operating area. Total consideration was $31.2 million, before closing adjustments, consisting of 4,033,708 Common Shares valued at $6.85 per Common Share (based on the closing price of the Common Shares on the date of closing) and cash of $3.6 million.

We suspended our dividend reinvestment plan and our stock dividend plan effective for our May 15, 2017 dividend.

On June 30, 2017 we closed an acquisition of assets in the Midale area of southeast Saskatchewan and in the House Mountain area of Alberta for a total purchase price of $296 million before closing adjustments. The purchase price was partially funded through the proceeds of a public offering of subscription receipts at a price of $5.50 per subscription receipt for gross proceeds of $296 million which closed on June 21, 2017. In accordance with the terms of the subscription receipts, each subscription receipt automatically converted into a Common Share on the closing of the acquisition.

On June 30, 2017 we announced an increase to our Credit Facility from $150 million to $325 million.

On August 1, 2017 we appointed Stephanie Sterling to our Board of Directors.

On September 1, 2017 David Kelly was appointed Vice-President, Saskatchewan.

On October 31, 2017, we closed a disposition of a 2.5% gross overriding royalty on certain of our Wainwright properties for proceeds of $14.5 million.

Effective November 9, 2017, Dale Orton was appointed Chief Operating Officer and Jason LaForge was appointed to Vice President, Central.

Robert Wollmann was appointed Senior Vice President, Exploration effective November 15, 2017.

On December 14, 2017, we issued 475,000 flow-through Common Shares pursuant to a private placement at $6.00 per Common Share for gross proceeds of $2.9 million.

Developments in 2018

Effective January 9, 2018, Doug Smith retired as our Chief Financial Officer and Shawn Van Spankeren was appointed Chief Financial Officer effective January 15, 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 Debentures over a period of 12 months commencing on December 19, 2018. We repurchased and cancelled the maximum amount of 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 a sustainable dividend, 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 allows 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. As at March 20, 2020, we had purchased 2,570,246 Common Shares pursuant to the Share NCIB.

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 "**Current Debenture NCIB**") to purchase up to $4.45 million aggregate principal amount of our Debentures over a twelve month period. As at March 20, 2020, we had purchased $9,000 principal amount of Debentures pursuant to the Current Debenture NCIB.

Recent Developments

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. Our original budget called for capital spending of $67 million with $27 million to be spent in the first quarter of 2020. As of March 9, we were able to safely suspend drilling and completion operations as well as other capital programs having spent approximately $22 million. This resulted in the drilling and completing of the majority of our Southern area drill program for the year and with several wells that are completed but not tied in and one well requiring completion. We anticipate that the production from this drill program will allow us to maintain approximately the same average production levels as 2019 with minimal capital spending for the remainder of the year.

Our revised 2020 capital budget is now $31 million, of which $22 million has been spent and $9 million is planned for the balance of the year. These funds are necessary to complete scheduled facility turnarounds and to maintain safe operations as well as to maintain our base production. Our revised budget contemplates exiting 2020 at a similar debt level as 2019.

In addition, we have indefinitely suspended our dividend, effective March 2020, in order to preserve our balance sheet. This will be evaluated throughout the year pending a recovery in oil prices.

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 an oil focused Canadian company built to provide investors with total returns comprised of yield plus growth through the ownership of crude oil production focused in all season access areas in Alberta and Saskatchewan. 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 with the goal of building a dividend paying junior oil focused company from the ground up. Since we commenced operations, 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, 2019, we had 60 full-time employees located at our head office and 117 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 environmental, social, and governance ("**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 inaugural ESG report prepared earlier this year. 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 (1.54 tonnes of $C0_2$ equivalent sequestered for every tonne of $C0_2$ equivalent emissions in 2018) 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 February 26, 2020. The statement is effective as of December 31, 2019. 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, 2019 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, 2019 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, 2019 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	38,370	32,790	23,280	20,478	38,390	34,890	2,877	2,211
Developed Non-Producing	650	593	744	675	5,065	4,458	139	107
Undeveloped	4,941	4,418	2,840	2,334	3,249	2,770	260	224
TOTAL PROVED	43,962	37,801	26,864	23,486	46,704	42,117	3,276	2,542
TOTAL PROBABLE	14,317	12,037	8,023	6,781	16,312	14,695	1,079	861
TOTAL PROVED PLUS PROBABLE	58,279	49,838	34,887	30,268	63,016	56,812	4,355	3,403

Note:

(1) Includes solution gas.

	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2019 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	1,656	1,243	949	766	646	15.48
Developed Non-Producing (2)	(128)	(53)	(31)	(22)	(17)	(14.43)
Undeveloped	233	141	96	69	51	12.95
TOTAL PROVED	1,761	1,331	1,014	813	679	14.32
TOTAL PROBABLE	1,005	454	270	185	138	12.20
TOTAL PROVED PLUS PROBABLE	2,766	1,785	1,284	999	817	13.81

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, 2019 AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
PROVED:					
Developed Producing	1,508	1,175	914	747	634
Developed Non-Producing	(103)	(42)	(25)	(19)	(16)
Undeveloped	178	108	74	54	40
TOTAL PROVED	1,582	1,241	964	782	658
TOTAL PROBABLE	785	349	209	146	111
TOTAL PROVED PLUS PROBABLE	2,367	1,591	1,173	928	769

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2019
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	6,122	919	2,610	220	612	1,761	179	1,582
TOTAL PROVED PLUS PROBABLE	8,490	1,332	3,506	270	615	2,766	399	2,367

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, 2019 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)	680	15.89
Heavy Crude Oil (3)	312	12.99
Conventional Natural Gas (4)	23	5.57
	1,014	14.32
TOTAL PROVED PLUS PROBABLE		
Light and Medium Crude Oil (3)	856	15.10
Heavy Crude Oil (3)	401	12.91
Conventional Natural Gas (4)	27	5.14
	1,284	13.81

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.

(d) 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, 2020. 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, 2019

	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									
2020	61.00	72.64	57.57	70.22	2.04	26.36	42.09	0	0.7600
2021	63.75	76.06	62.35	73.15	2.32	29.80	47.03	2	0.7700
2022	66.18	78.35	64.33	74.95	2.62	32.94	50.66	2	0.7850
2023	67.91	80.71	66.23	77.19	2.71	34.00	52.21	2	0.7850
2024	69.48	82.64	67.96	79.05	2.81	34.89	53.48	2	0.7850
2025	71.07	84.60	69.72	80.92	2.89	35.78	54.77	2	0.7850
2026	72.68	86.57	71.49	82.82	2.96	36.69	56.07	2	0.7850
2027	74.24	88.49	73.19	84.66	3.03	37.57	57.32	2	0.7850
2028	75.73	90.31	74.80	86.40	3.10	38.41	58.50	2	0.7850
2029	77.24	92.17	76.43	88.17	3.17	39.26	59.71	2	0.7850
2030	78.79	94.01	77.96	89.94	3.24	40.11	60.90	2	0.7850
2031	80.36	95.89	79.52	91.74	3.30	40.91	62.12	2	0.7850
2032	81.97	97.81	81.11	93.57	3.37	41.73	63.36	2	0.7850
2033	83.61	99.76	82.73	95.44	3.43	42.56	64.63	2	0.7850
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.7850

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, 2019, excluding price risk management activities, were $62.73/Bbl for light and medium crude oil, $57.70/Bbl for heavy crude oil, $1.59/Mcf for natural gas and $17.68/Bbl for NGLs.

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2019, 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, 2018	**43,873**	**14,175**	**58,048**	**27,749**	**8,177**	**35,926**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [(1)]	2,566	1,273	3,839	372	1,048	1,421
Technical Revisions [(2)]	1,975	(1,031)	944	999	(1,109)	(110)
Acquisitions [(3)]	-	-	-	-	-	-
Dispositions[(3)]	-	-	-	(24)	(8)	(31)
Economic Factors [(4)]	(430)	(100)	(530)	(146)	(85)	(231)
Production	(4,022)	-	(4,022)	(2,087)	-	(2,087)
December 31, 2019	**43,962**	**14,317**	**58,279**	**26,864**	**8,023**	**34,887**

	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, 2018	**54,160**	**17,308**	**71,468**	**2,909**	**870**	**3,779**
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery [(1)]	1,168	1,057	2,225	159	98	257
Technical Revisions [(2)]	(1,338)	(1,456)	(2,794)	632	130	762
Acquisitions [(3)]	-	-	-	-	-	-
Dispositions [(3)]	-	-	-	-	-	-
Economic Factors [(4)]	(1,619)	(597)	(2,217)	(84)	(20)	(104)
Production	(5,667)	-	(5,667)	(339)	-	(339)
December 31, 2019	**46,704**	**16,312**	**63,016**	**3,276**	**1,079**	**4,355**

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 2019, 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 Jenner area; and (iii) negative natural gas reserve revisions were due to natural gas utilization as fuel for power generation.

(3) There were no reserves acquisitions in 2019 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
2017	1,838	1,968	166	1,436	3,330	4,307	150	197
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

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 8.6 MMBoe of proved undeveloped reserves in the Report with $138.2 million of associated undiscounted capital, of which $62.0 million is forecast to be spent in the first two years. A total of $114.0 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
2017	663	687	370	1,227	1,409	2,124	69	100
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

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 6.8 MMBoe of probable undeveloped reserves in the Report with $42.0 million of associated undiscounted capital, of which $31.8 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 $604 million undiscounted (and inflated by two percent) and $77.3 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 $11 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)
2020	39	44
2021	43	47
2022	36	54
2023	28	34
2024	22	28
Remaining	52	63
Total (Undiscounted)	220	270
Discounted (10%)	156	189

Note:

(1) Includes $50 million and $61 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 2020 capital budget was $67 million. In March of 2020, we reduced our 2020 capital budget to approximately $31 million, which is below the 2020 future development costs in the Report. 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, 2019. 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 2019 production was approximately 5,046 Boe/d (52% light and medium crude oil, 30% 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 2019, we continued our successful drilling program in Bantry, drilling four net Glauconite horizontal wells and three net Ellerslie horizontal wells. In addition, we also drilled 10 net stratigraphic test wells. We have drilled seven net horizontal wells at Bantry to date in 2020. We do not plan to drill any additional wells in 2020. 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 2019 production for this property was 2,723 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 2,097 Boe/d (91% light and medium crude oil and 9% NGL) during 2019.

Grande Prairie, Alberta

Located to the west of the City of Grande Prairie, this property produced 2,426 Boe/d (33% light and medium crude oil, 21% NGL and 46% 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 2019 and currently do not have any plans to drill any wells in 2020.

Wainwright, Alberta

Wainwright is located 195 kilometres southeast of Edmonton, Alberta. In 2019, the Wainwright properties (including the Chauvin, Forestburg and Hayter areas) produced approximately 4,754 Boe/d (9% light and medium crude oil, 89% heavy oil and 2% conventional natural gas). Crude oil makes up 98% of the production and 94% of the reserves assigned to this area are proved plus probable producing reserves. 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 77.2% 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 2019 production from these properties was 3,273 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 enhanced oil recovery ("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.

In 2019, we successfully drilled 2 horizontal wells further increasing the long term development potential of the Midale unit. We currently do not plan to drill any wells in this area in 2020.

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, 2019.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING		PRODUCING		NON-PRODUCING	
	Gross	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,768	1,459	1,250	938	159	94	247	163
Saskatchewan	811	180	330	84	-	-	-	-
Total	2,579	1,639	1,580	1,022	159	94	247	163

Note:

(1) Does not include 1,647 gross (1,053 net) service wells.

Of the non-producing wells, 97 gross (68.6 net) were capable of production and had reserves assigned to them. As of the date of this Annual Information Form 37 gross (26 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, 2019.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	256,828	170,337	477,977	323,009	734,804	493,346
Saskatchewan	20,493	14,881	31,037	25,765	51,531	40,646
Total	277,320	185,218	509,014	348,774	786,336	533,992

Notes:

(1) Rights to explore, develop and exploit 48,671 net acres of our land holdings could expire by December 31, 2020 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, 2019 we held 477,817 gross acres (277,739 net acres) to which no reserves are currently attributed, all of which are located in Canada. Rights to explore, develop and exploit 35,692 net acres of these land holdings could expire by December 31, 2020 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 17 to our financial statements for the year ended December 31, 2019.

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 2025, or beyond.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2019.

EXPENDITURE	YEAR ENDED DECEMBER 31, 2019 ($000S)
Property acquisition costs – Unproved properties [(1)]	744
Property acquisition costs – Proved properties	396
Exploration costs [(2)]	2,660
Development costs [(3)]	60,199
Total	63,999

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, 2019.

	DEVELOPMENT		EXPLORATORY[(1)]	
	GROSS	NET	GROSS	NET
Conventional Natural Gas	-	-	-	-
Light and Medium Crude Oil	16	15.5	10	10.0
Dry	-	-	-	-
Service	-	-	-	-
Total	16	15.5	10	10.0

Note:

(1) Includes stratigraphic test wells.

We have drilled seven (7.0 net) horizontal wells at Bantry to date in 2020. We do not plan to drill any additional wells in 2020. 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, 2019, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the heading "*Disclosure of Reserves Data*".

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	HEAVY CRUDE OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE (Boe/d)
Proved	10,889	5,576	13,272	885	19,562
Probable	343	401	664	28	883
Proved plus Probable	11,232	5,977	13,936	913	20,445

Note:

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

Finding, Development and Acquisition Costs

The following table summarizes our finding, development and acquisition costs for the periods indicated.

(1)(2)(3)(4)(5)	2019	THREE YEAR AVERAGE
Finding, Development and Acquisition Cost (FD&A)		
Proved Reserves	$19.57	$12.35
Proved plus Probable Reserves	$20.06	$11.05

Notes:

(1) For 2019, finding and development and FD&A costs were essentially the same, as there were no reserve acquisitions in 2019 and only a very minor disposition of 31 MBoe of total proved plus probable reserves. Acquisitions and dispositions have a significant impact on our ongoing reserve replacement costs and disclosing only finding and development costs could result in an inaccurate portrayal of our cost structure.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total FD&A related to reserves additions for that year.

(3) FD&A excludes capital related to fair value adjustments on acquisitions, capitalized overhead and non-cash expenditures for the decommissioning obligation and capitalized share-based compensation.

(4) FD&A is an oil and gas metric, see "*Oil and Gas Advisory*".

(5) FD&A costs are used as a measure of capital efficiency and are calculated by dividing the development capital expenditures, net of acquisitions and dispositions for the period, including the change in undiscounted inflated FDC, by the change in reserves, incorporating revisions and production for the same period.

(6) These costs are calculated based on "company interest" reserves (including royalty interest).

Production History

The following table indicates our average daily production for the year ended December 31, 2019.

	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)	2,621	1,500	77	5,086	5,046
Grande Prairie	804	-	499	6,743	2,426
House Mountain	1,910	-	187	-	2,097
Mitsue	2,014	-	166	3,261	2,723
Wainwright (2)	449	4,220	3	486	4,754
Midale, SK	3,273	-	-	-	3,273
Total	11,071	5,720	932	15,576	20,319

Notes:

(1) Includes Alderson, Duchess, Rosemary, Kinnivie and Jenner areas.
(2) Includes 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 2019				YEAR ENDED
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	DEC. 31, 2019
Average Daily Production (1)					
Light and Medium Crude Oil (Bbls/d)	11,103	11,045	10,914	11,222	11,071
Heavy Crude Oil (Bbls/d)	5,684	5,952	5,710	5,535	5,720
Natural Gas Liquids (Bbls/d)	964	939	932	893	932
Conventional Natural Gas (Mcf/d)	15,930	15,906	15,022	15,459	15,576
Combined (Boe/d)	20,407	20,587	20,059	20,227	20,319
Average Prices Received					
Light and Medium Crude Oil ($/Bbl)	60.52	68.03	62.25	60.19	62.73
Heavy Crude Oil ($/Bbl)	55.76	64.07	58.13	52.41	57.70
Natural Gas Liquids ($/Bbl)	18.98	17.38	15.54	18.83	17.68
Conventional Natural Gas ($/Mcf)	2.38	1.11	0.80	2.04	1.59
Combined ($/Boe)	51.21	56.67	51.74	50.12	52.45
Royalties					
Light and Medium Crude Oil ($/Bbl)	9.44	11.46	13.14	12.81	11.64
Heavy Crude Oil ($/Bbl)	7.36	9.76	8.63	7.58	8.52
Natural Gas Liquids ($/Bbl)	2.38	0.77	1.68	2.36	1.86
Conventional Natural Gas ($/Mcf)	0.09	0.02	0.02	0.10	0.05
Combined ($/Boe)	7.37	8.97	9.76	9.36	8.87
Operating Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	27.16	23.81	23.98	24.00	24.73
Heavy Crude Oil ($/Bbl)	26.87	22.98	23.27	23.54	24.14
Natural Gas Liquids ($/Bbl)	4.45	5.62	5.80	4.06	4.98
Conventional Natural Gas ($/Mcf)	0.18	0.99	0.76	0.50	0.61
Combined ($/Boe)	22.63	20.28	20.57	20.31	20.94
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.20	0.21	0.11	0.10	0.16
Heavy Crude Oil ($/Bbl)	0.21	0.37	0.33	0.23	0.29
Natural Gas Liquids ($/Bbl)	0.92	0.97	0.99	0.99	0.97
Conventional Natural Gas ($/Mcf)	0.11	0.12	0.13	0.13	0.13
Combined ($/Boe)	0.19	0.49	0.36	0.27	0.33
Netback Received					
Light and Medium Crude Oil ($/Bbl)	23.72	32.55	25.02	23.28	26.20
Heavy Crude Oil ($/Bbl)	21.32	30.96	25.90	21.06	24.75
Natural Gas Liquids ($/Bbl)	11.23	10.02	7.07	11.42	9.86
Conventional Natural Gas ($/Mcf)	1.69	0.28	(0.12)	1.30	0.80
Combined ($/Boe)	21.02	26.93	21.05	20.18	22.31

Notes:

(1) Before the deduction of royalties.

(2) Operating costs 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.

Debentures

The Debentures were issued under and pursuant to the provisions of the Indenture. The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Indenture, a copy of which has been filed under our profile on SEDAR at www.sedar.com.

General

The Debentures are limited to an aggregate principal amount of $50 million. We may, however, from time to time, without the consent of the holders of any outstanding Debentures, issue debentures in addition to the Debentures outstanding. As of March 20, 2020 an aggregate of $45 million aggregate principal amount of Debentures were outstanding.

The Debentures are issued in denominations of $1,000 and integral multiples thereof. The Debentures are dated October 6, 2015 and have a maturity date of December 31, 2020.

The Debentures bear interest from October 6, 2015 at 5.50% per annum, payable semi-annually on June 30 and December 31 in each year computed on the basis of a 365-day year. Interest on the Debentures is payable in lawful money of Canada.

Conversion Privilege

Each Debenture is convertible at any time at the option of the holder into fully paid and non-assessable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earliest of: (i) December 31, 2020; (ii) the last Business Day immediately preceding a redemption date; and (iii) the last Business Day immediately preceding the date specified for purchase in a Debenture Offer (as defined herein), in each case, at the conversion price of $10.50 per Debenture, representing a conversion rate of approximately 95.2381 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in accordance with the Indenture. Upon conversion of any Debentures, the holder will be eligible to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest thereon in cash up to, but excluding, the date of conversion.

The Indenture provides for the adjustment of the conversion price in certain events including: (i) the subdivision or consolidation of the outstanding Common Shares; (ii) the issuance of Common Shares or securities convertible into Common Shares by way of stock dividend or otherwise to the holders of all or substantially all of the outstanding Common Shares other than an issue of Common Shares to holders of Common Shares who have elected to receive dividends in the form of Common Shares in lieu of receiving cash dividends not in excess of $0.07 per Common Share per month; (iii) the issuance of options, rights or warrants to all or substantially all the holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price of the Common Shares; (iv) the distribution to all holders of Common Shares of any securities or assets (other than securities or assets in respect of any event described in (ii), (iii), (v) or (vi)); (v) the payment to all holders of Common Shares in respect of an issuer bid for Common Shares us to the extent that the market value of the payment exceeds the then market price of the Common Shares on the date of expiry of the bid; and (vi) the payment of cash dividends to holders of Common Shares in excess of $0.07 per Common Share per month.

Subject to prior regulatory approval, if required, there will be no adjustment of the conversion price in respect of any event described in (ii), (iii) or (iv) above if, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. We will not be required to make adjustments to the conversion price unless the cumulative effect of such adjustments would change the conversion price by at least 1%. However, any adjustments that are less than 1% of the conversion price will be carried forward and taken into account when determining subsequent adjustments.

In the case of: (i) any reclassification, capital reorganization or change (other than a change resulting only from consolidation or subdivision) of the Common Shares; (ii) our amalgamation, arrangement, consolidation or merger with or into any other entity; (iii) any sale, transfer or other disposition of our properties and assets as, or substantially as, an entirety to any other entity; or (iv) our liquidation, dissolution or winding-up, the terms of the conversion privilege will be adjusted so that each Debenture will, after such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up, be exercisable for the kind and amount of our securities or property, or of such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up if on the effective date thereof it had been the holder of the number of Common Shares into which the Debenture was convertible prior to the effective date thereof.

No fractional Common Shares will be issued upon conversion of the Debentures. In lieu thereof, we will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share. Upon conversion, we may offer, and the converting holder may agree to the delivery of, cash for all or a portion of the Debentures surrendered in lieu of Common Shares.

Redemption and Purchase

Prior to December 31, 2020, the Debentures may be redeemed by us, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by Computershare on a *pro rata* basis or in such other manner as Computershare deems equitable, subject to the consent of the Toronto Stock Exchange (or such other recognized exchange on which the Common Shares may be listed).

We have the right to purchase Debentures for cancellation in the market, by tender or by private contract, at any time, subject to regulatory requirements.

Payment upon Redemption or Maturity

On any date set for redemption or the maturity date of December 31, 2020 as applicable, we will repay the indebtedness represented by the Debentures by paying to Computershare in lawful money of Canada an amount equal to the principal amount of the outstanding Debentures, together with accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption or December 31, 2020. On any date set for redemption or the maturity date, as applicable, we may, at our option, on not more than 60 days and not less than 40 days prior written notice and subject to any required regulatory approvals, provided that no event of default has occurred and is continuing, elect to satisfy our obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Debentures. Payment for such Debentures subject to the election would be satisfied by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures subject to the election which are to be redeemed or have matured by 95% of the Current Market Price of the Common Shares on such date. In the event a holder of Debentures exercises its conversion right following delivery of a notice of redemption by us, such holder shall be entitled to receive the applicable number of Common Shares to be received on conversion on the Business Day immediately preceding the date set for redemption, plus any accrued and unpaid interest for the period from the latest interest payment date to but excluding date of conversion. Any accrued and unpaid interest will be paid in cash.

No fractional Common Shares will be issued upon redemption or maturity of the Debentures; in lieu thereof, we will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share.

Cancellation

All Debentures converted, redeemed or purchased will be cancelled and may not be reissued or resold.

Rank

The Debentures are direct, unsecured obligations of us and are fully subordinated to all Senior Indebtedness (as defined below). The Debentures rank equally with one another and, other than Senior Indebtedness, with all our other existing and future unsecured indebtedness and will rank *pari passu* with all of our other existing and future unsecured subordinated indebtedness to the extent that it is subordinated on the same terms, and have priority over the payment of any declared but unpaid dividends on the Common Shares, as more particularly described below under " – *Subordination*" below. The Indenture does not restrict our ability from incurring additional indebtedness, including Senior Indebtedness, or from mortgaging, pledging or charging their respective properties to secure any indebtedness or liabilities, including Senior Indebtedness.

Subordination

The payment of the principal and premium, if any, of, and interest on, the Debentures will be subordinated and postponed, and subject in right of payment to the full and final payment of all of our Senior Indebtedness. "**Senior Indebtedness**" is defined in the Indenture, as the principal of and premium, if any, and interest on and other amounts in respect of all indebtedness of us (whether outstanding as at the date of the Indenture or thereafter incurred), other than indebtedness evidenced by the Debentures and all other existing and future indebtedness or other instruments of us which, by the terms of the instrument creating or evidencing the indebtedness, is expressed to be *pari passu* with, or subordinate in right of payment to, the Debentures.

The Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to us, or to our property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of us, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of us, then holders of Senior Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Indenture also provides that we will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures: (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; or (b) at any time when a default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of Senior Indebtedness and the notice of such default, event of default or acceleration has been given by or on behalf of holders of Senior Indebtedness to us, unless such notice has been revoked, such default or event of default has been cured or the Senior Indebtedness has been repaid or satisfied in full.

We and Computershare are also authorized (and obligated upon a request from us) under the Indenture to enter into subordination agreements on behalf of the holders of Debentures with any holder of Senior Indebtedness.

Repurchase upon a Change of Control

Within 30 days following the occurrence of a change of control, we will be required to make a cash offer to purchase all of the Debentures (the "**Debenture Offer**") at an offer price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. A change of control shall include: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids* and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 – *Take-Over Bids and Issuer Bids*) of ownership of, or voting control or direction over, 50% or more of the issued and outstanding Common Shares; or (ii) the sale or other transfer of all or substantially all of our consolidated assets, excluding a sale, merger, reorganization or similar transaction if the previous holders of Common Shares immediately prior to such transaction hold at least 50% of the voting control or direction in such merged, reorganized, arranged, combined or other continuing entity (and in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets) (each a "**Change of Control**").

The Indenture contains notification and repurchase provisions requiring us to give written notice to Computershare of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. Computershare will thereafter promptly mail to each holder of Debentures a notice of the change of control together with a copy of the Debenture Offer to repurchase all outstanding Debentures.

If Debentures representing 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control are tendered for purchase following a Change of Control (other than Debentures held at the date of the take-over bid by or on behalf of the offeror, associates or affiliates of the offeror or any one acting jointly or in concert with the offeror), we will have the right to redeem all remaining Debentures in cash on the purchase date at the offer price. Notice of such redemption must be given to Computershare by us within ten days following expiry of the right of the holders of the Debentures to require repurchase after the Change of Control and, as soon as possible thereafter, by Computershare to the holders of Debentures not tendered for purchase.

We will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of Debentures in the event of a Change of Control.

Cash Change of Control

In addition to the requirement for us to make a Debenture Offer in the event of a Change of Control, if a Change of Control occurs on or before December 31, 2020 in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting a change of control consists of: (i) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenters' appraisal rights); (ii) equity securities that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (iii) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then subject to regulatory approvals, during the period beginning ten trading days before the anticipated date on which the Change of Control becomes effective and ending 30 days after the Debenture Offer is delivered, holders of Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, subject to and upon completion of the Change of Control, in addition to the number of Common Shares they would otherwise be entitled to receive as set out under "– *Conversion Privilege*" above, a make-whole premium of an additional number of Common Shares per $1,000 principal amount of Debentures as set out below.

The number of additional Common Shares per $1,000 principal amount of Debentures constituting the relevant make-whole premium will be determined by reference to the table below and is based on the date on which the Change of Control becomes effective and the offer price paid per Common Share in the transaction constituting the Change of Control. If holders of Common Shares receive (or are entitled and able in all circumstances to receive), only cash in the transaction, the offer price will be the cash amount paid per Common Share. Otherwise, the offer price will be equal to the Current Market Price of the Common Shares immediately preceding the effective date of such transaction.

The following table shows what the make-whole premium would be for each hypothetical offer price and effective date set out below, expressed as additional Common Shares per $1,000 principal amount of Debentures. For greater certainty, we will not be obliged to pay the make-whole premium other than by issuance of Common Shares upon conversion, subject to the provision relating to adjustment of the conversion price in certain circumstances and following the completion of certain types of transactions described under "– *Conversion Privilege*" above.

Make-Whole Premium Upon a Change of Control
(Number of Additional Common Shares per $1,000 Debenture)

OFFER	EFFECTIVE DATE			
PRICE	DEC 31/17	DEC 31/18	DEC 31/19	DEC 31/20
$8.30	25.2438	25.2438	25.2438	25.2438
$8.50	23.7271	22.4090	22.4090	22.4090
$8.75	21.6011	19.5760	19.0476	19.0476
$9.00	19.6311	17.5078	15.8730	15.8730
$9.50	16.0789	13.8916	10.0251	10.0251
$10.00	12.9560	10.8770	4.7619	4.7619
$10.50	10.3867	8.3724	1.6114	1.6114
$11.00	8.2545	6.3155	0.7300	0.7300
$12.00	5.0017	3.3125	0.3533	0.3533
$13.00	2.7677	1.4762	0.0	0.0
$14.00	1.2850	0.5679	0.0	0.0
$15.00	0.3927	0.1927	0.0	0.0
$16.00	0.0144	0.0	0.0	0.0
$17.00	0.0	0.0	0.0	0.0
$18.00	0.0	0.0	0.0	0.0

The actual offer price and effective date may not be set out in the table, in which case:

(a) if the actual offer price on the effective date is between two offer prices in the table or the actual effective date is between two effective dates in the table, the make-whole premium will be determined by a straight-line interpolation between the make-whole premiums set out for the two offer prices and the two effective dates in the table based on a 365-day year, as applicable;

(b) if the offer price on the effective date is equal to or exceeds $18.00 per Common Share, subject to adjustment as described below, the make-whole premium will be zero; and

(c) if the offer price on the effective date is less than $8.30 per Common Share, subject to adjustment as described below, the make-whole premium will be zero.

The offer prices set out in the previous table will be adjusted as of any date on which the conversion price of the Debentures is adjusted. The adjusted offer prices will equal the offer prices applicable immediately prior to such adjustment multiplied by a fraction, the numerator of which is the conversion price as so adjusted and the denominator of which is the conversion price immediately prior to the adjustment giving rise to the offer price adjustment. The number of additional Common Shares set out in the table above will be adjusted in the same manner as the conversion price as set out above under "– *Conversion Privilege*", other than by operation of an adjustment to the conversion price by adding the make-whole premium as described above.

Interest Payment Election

We may elect, from time to time, subject to applicable regulatory approval, to satisfy our obligation to pay interest on an interest payment date, (i) in cash; (ii) unless an event of default has occurred and is continuing, by delivering sufficient Common Shares to Computershare for sale, to satisfy an obligation to pay interest on the interest payment date, in which event holders of the Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares; or (iii) any combination of (i) and (ii) above.

The Indenture provides that, upon us making the election to satisfy interest in Common Shares, Computershare will: (i) accept delivery from us of Common Shares; (ii) accept bids with respect to, and consummate sales of, such Common Shares, each as we shall direct in our absolute discretion through investment banks, brokers or dealers identified by us; (iii) invest the proceeds of such sales in securities issued or guaranteed by the Government of Canada which mature prior to the applicable interest payment date, and use the proceeds received from investment in such permitted government securities, together with any additional cash provided by us, to satisfy the interest payable; and (iv) perform any other action necessarily incidental thereto.

The Indenture sets out the procedures to be followed by us and Computershare in order to effect the payment of interest in Common Shares. If such election is made, the sole right of a holder of Debentures in respect of interest will be to receive a cash payment equal to the interest owed on his Debentures from Computershare out of the proceeds of the sale of Common Shares (plus any amount received by Computershare from us) in full satisfaction of the interest payable, and the holder of such Debentures will have no further recourse to us in respect of the interest payable.

Notwithstanding the foregoing, neither the making the election nor the consummation of sales of Common Shares will: (i) result in the holders of the Debentures not being entitled to receive, on the applicable interest payment date, cash in an aggregate amount equal to the interest payable on such interest payment date; or (ii) entitle or require such holders to receive any Common Shares in satisfaction of the interest payable.

Modification

The rights of the holders of Debentures as well as any other series of debentures that have been or may be issued under the Indenture may be modified in accordance with the terms of the Indenture. For that purpose, among others, the Indenture contains certain provisions which make binding on all holders of outstanding Debentures, resolutions passed at meetings of the holders of outstanding Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the then-outstanding Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the then-outstanding Debentures. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of each particularly-affected series of debentures, as the case may be. Under the Indenture, certain amendments of a technical nature or which are not prejudicial to the rights of the holders of the Debentures may be made to the Indenture without the consent of the holders of the Debentures.

Consolidation, Mergers or Sales of Assets

The Indenture provides that we may not, without the consent of the holders of the Debentures, consolidate or amalgamate with or merge into any person or sell, convey, transfer or lease all or substantially all of our properties and assets to another person (other than our direct or indirect wholly-owned subsidiaries) unless:

(a) the resulting, surviving, continuing or transferee person expressly assumes all of our obligations under the Debentures and Indenture;

(b) if such resulting, surviving, continuing or transferee person is organized otherwise than under the laws of Canada, any province or territory thereof, the United States or any state or district thereof, it attorns to the jurisdiction of the courts of Alberta;

(c) the Debentures will be valid and binding obligations of the resulting, surviving, continuing or transferee person entitling the holders thereof, as against such person, to all the rights of holders of Debentures under the Indenture; and

(d) after giving effect to the transaction, no event of default, and no event that, after notice or lapse of time, or both, would become an event of default, will occur; and

(e) such other conditions as may be described in the Indenture are met.

Although such transactions are permitted under the Indenture, certain of the foregoing transactions could constitute a Change of Control, which would require us to offer to purchase the Debentures as described above.

Events of Default

The Indenture provides that an event of default in respect of the Debentures will occur if certain events described in the Indenture occur, including if any one or more of the following events has occurred and is continuing with respect to the Debentures: (i) failure for 15 days to pay interest on the Debentures when due; (ii) failure to pay principal or premium, if any (whether by payment in cash or delivery of Common Shares), on the Debentures when due, whether at maturity, upon redemption, on a change of control, by declaration or otherwise; (iii) default in the delivery, when due, of any Common Shares or other consideration, including any make-whole premium, payable upon conversion with respect to the Debentures, which default continues for 15 days; (iv) default in the observance or performance of any covenant or condition of the Indenture and the failure to cure (or obtain a waiver for) such default for a period of 30 days after notice in writing has been given by Computershare or from holders of not less than 25% of the aggregate principal amount of the Debentures specifying such default and requiring us to rectify or obtain a waiver for same; and (v) certain events of bankruptcy, insolvency or reorganization of us under bankruptcy or insolvency laws.

If an event of default has occurred and is continuing, Computershare may, in its discretion, and will, upon the request of holders of not less than 25% in principal amount of the then outstanding Debentures (declare the principal of (and premium, if any) and interest on all outstanding Debentures to be immediately due and payable.

Offers for Debentures

The Indenture contains provisions to the effect that if an offer is made for the Debentures which is a take-over bid within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids*, the Debentures are considered equity securities, and not less than 90% of the principal amount of the then outstanding Debentures (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by those who did not accept the offer on the terms offered by the offeror.

Credit Facility

The Credit Facility consists of a $295 million syndicated term credit facility and a $30 million non-syndicated operating term credit facility. The available lending limits of the Credit Facility are reviewed semi-annually based on our reserves, future commodity prices and costs. In connection with the most recent review of the Credit Facility, the lenders determined our borrowing base to be $325 million.

The Credit Facility is available on a revolving basis until May 23, 2020 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 22, 2021.

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 0.5 to 2.5%, and bankers' acceptances and/or LIBOR loans, which are subject to fees and margins ranging from 1.5 to 3.5%. Interest and standby fees on the undrawn amounts of the Facilities depend upon certain ratios. The Credit Facility is secured by a general security agreement over all of our assets.

There are no financial or other restrictive covenants related to the Credit Facility provided that we are not in default of the terms of the Credit Facility. See "*Risk Factors – Credit Facility Arrangements*".

MARKET FOR OUR SECURITIES

Trading Price and Volume

Common Shares

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
2019			
January	2.57	2.06	10,984,846
February	2.59	1.91	9,732,582
March	2.83	1.99	16,543,310
April	3.50	2.55	14,342,527
May	3.14	2.41	8,938,444
June	2.67	2.24	4,999,541
July	2.59	2.19	7,573,388
August	2.46	2.01	7,054,042
September	2.83	2.15	6,037,817
October	2.52	1.92	6,255,560
November	2.19	2.03	8,949,748
December	2.65	1.93	8,673,953
2020			
January	2.91	2.30	9,728,755
February	2.47	1.77	8,076,701
March (to March 20)	1.99	0.30	15,630,429

Debentures

Our Debentures trade on the Toronto Stock Exchange under the trading symbol "CJ.DB" and commenced trading on the Toronto Stock Exchange on October 6, 2015. The following table sets out the high and low trading price and aggregate volume of trading for the periods noted below for our Debentures.

PERIOD	HIGH	LOW	VOLUME
2019			
January	95.50	91.99	4,180
February	97.00	92.00	76,770
March	97.50	93.25	10,590
April	99.50	95.00	8,120
May	98.75	92.01	2,060
June	98.50	95.99	3,475
July	98.85	92.00	3,840
August	99.00	97.00	7,510
September	99.00	98.00	17,070
October	99.49	98.01	6,280
November	99.40	97.03	13,080
December	100.30	97.00	5,510
2020			
January	100.69	99.53	5,702
February	100.03	99.00	20,750
March (to March 20)	99.50	48.00	2,980

Prior Sales

During the year ended December 31, 2019 we granted a total of 2.9 million bonus awards pursuant to our restricted bonus award 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, 2019. See note 14 of our annual financial statements for the year ended December 31, 2019 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 recently 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.	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) 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

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

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 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*.

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 35 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 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) ($)	ALL OTHER FEES (4) ($)
2018	185,000	60,000	7,350	-
2019	185,000	60,000	5,490	25,000

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

Dividends and Dividend Policy

On January 7, 2014 our Board of Directors adopted our dividend policy. Our long-term objective is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow our current production base by a target of 5% to 10% annually. This in turn, is expected to provide a stronger base of cash flow from operating activities leading to consistent dividends into the future. Cash dividends are paid on the 15th day (or if such date is 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 amount of future cash dividends, if any, will be in the sole discretion of the 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. 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 "*General Development of our Business – Developments in 2018*". On June 10, 2019, we increased 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 on August 15, 2019. See "*General Development of our Business – Developments in 2019*". On March 17, 2020, we suspended our dividend due to the current economic environment. See "*General Development of our Business – Recent Developments".*

Our Credit Facility contains restrictions on our ability to pay dividends in certain circumstances. 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.

Cash dividends are not guaranteed. Although we intend to make dividends in the amount indicated to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends applicable law and other factors beyond our control. See "*Risk Factors*".

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

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

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations 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 regulations carefully. Although laws and regulations are a matter of public record, we are unable to predict what additional laws, regulations or amendments governments may enact in the future.

We hold interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian provinces of Alberta and Saskatchewan. Our assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of our upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (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; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude 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 certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Alberta and Saskatchewan.

Pricing and Marketing in Canada

Crude Oil

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

Natural Gas

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

Natural Gas Liquids

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

Exports from Canada

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

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

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

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

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

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

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

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

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal.

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

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Regulatory Authorities and Environmental Regulation – Federal*" in these Industry Conditions.

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 Bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2010, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

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

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

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

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

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), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being revised and finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., 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, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 Bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million Bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for March 2020 and April 2020 is set at 3.81 million Bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The *Curtailment Rules* are set to be repealed by December 31, 2020.

We were subject to a curtailment order in 2019. For the first nine months of 2019, our average Alberta oil production was curtailed to a range of 13,500 to 14,000 Bbls/d in 2019. As Cardinal does not produce more than 20,000 Bbls/d of Alberta oil, effective October 1, 2019 we were no longer restricted by a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

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

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

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

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

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

Land Tenure

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

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

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that 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 crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba approximately 19%, 6%, 20%, and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the

2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. We do not have any material operations on Indian reserve lands.

Royalties and Incentives

General

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

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

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

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells 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.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost

Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

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

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, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for Western Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

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

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Saskatchewan

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

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

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

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

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

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment, and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions including carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

"Designated projects" under the IAA include interprovincial or international pipelines that require more than 75km of new right of way, and will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

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. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. The case is expected to be heard in the fall of 2020.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53’00’’ north latitude and west of 126°38’36’’ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

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 legislation 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 objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible 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 by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. 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 for surface land 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. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

The AER monitors seismic activity across Alberta, in the context of assessing the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process 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 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.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. 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 Program

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). 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 AB LMR Program requires the licensee to provide the AER with a security deposit and 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 ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect our ability to obtain or transfer licenses.

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, including us, fund the Orphan Fund through a levy administered by the AER. 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.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company’s valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. 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, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. 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 it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to spend a percentage of their inactive liability as determined from the AB LMR Program. In 2019, this required spend was 4.33% of a company’s inactive liability. We are participating in the voluntary ABC program and thus receive a waiver for our remaining IWCP requirements.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. 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 Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Climate Change Regulation

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

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. 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 emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, 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 intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

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

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO^2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO^2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. 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. We have elected to opt-in to the TIER regulation under the aggregated facility approach and as of January 17, 2020 we have received confirmation of registration with Alberta Environment and Parks Climate Change Compliance Division.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO^2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Saskatchewan

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

The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

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 CO^2e 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 achieve 4.5 million tonne CO^2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO^2e between 2020 and 2030.

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

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

Accountability and Transparency

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

RISK FACTORS

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

COVID-19

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, has and may continue to adversely affect us by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas resulting in lower commodity prices, (ii) impairing our supply chain (for example, by limiting the manufacturing of materials or the supply of services used in our operations), and (iii) affecting the health of our workforce, rendering employees unable to work or travel.

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 the Organization of the Petroleum Exporting Countries ("**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 funds from operations 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 facilities, 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 COVID-19, the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East 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 Market Access*" and "*Weakness and Volatility in the Oil and Gas Industry"* in these Risk Factors.

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

Debenture Repayment

The current maturity date of our Debentures is December 31, 2020. We are considering various alternatives available to us to address the maturity of the Debentures. The options may include a draw down under the Credit Facility or arranging for alternate debt financing in order to fund the pay-out in cash of the principal amount together with the accrued and unpaid interest thereon. There is no certainty that we would be in a position to make such repayment. Even if we are able to use alternate debt financing in order to repay the Debentures, it may not be on commercially reasonable terms, or terms that are acceptable to us.

We also have the option of satisfying the obligation to pay the amount on the Debentures on the maturity date, in whole or in part, through the issuance of Common Shares. Settlement of the Debentures in this manner could result in significant dilution of existing Shareholders' interest which could negatively affect the market price of the Common Shares.

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, 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.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors to periodically determine our borrowing base. Commodity prices 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 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 Program*".

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.

Risks Associated with Forecast Prices

Our reserves as at December 31, 2019 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**.**

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

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. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends 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.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA.

The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including us.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. 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. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy oil products into and through British Columbia. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. 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

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, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, 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. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CERA, 2012 were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. 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.

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

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 concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during 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 the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on our financial and operational results. See "*Industry Conditions – 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 Program*".

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 – Regulatory Authorities and Environmental Regulation – 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 our regulatory obligations. Changes to the AB LMR Program administered by the AER, or 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. In addition, the AB LMR 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 Program*".

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 fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel 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 November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change. 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 and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". The 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 volatility 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 fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flow from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Geopolitical Risks

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

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. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

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.

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 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 Aboriginal 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

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 since our inception in 2011 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 Amended and Restated Credit Agreement made as of June 30, 2017 with respect to our Credit Facility, as amended by a first amending agreement dated November 22, 2017, a second amending agreement dated May 24, 2018 and a third amending agreement dated May 14, 2019;

2. the Restricted Bonus Award Plan; and

3. the Debenture Indenture between Cardinal Energy Ltd and Computershare Trust Company of Canada, dated October 6, 2015;

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 13, 2020. Additional financial information is contained in our financial statements for the year ended December 31, 2019 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 - 3 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 20, 2020

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	12-31-2017	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 Petroleum Consultants	December 31, 2019	Canada	-	1,284,374	-	1,284,374

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 Petroleum Consultants Ltd., Calgary Alberta, Canada February 26, 2020.

"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.

Approved by the Board of Directors on March 17, 2020.