ANNUAL INFORMATION FORM

For the Year Ended December 31, 2019

Dated March 20, 2020

TORC Oil & Gas Ltd

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DEFINITIONS

Capitalized terms in this Annual Information Form have the meanings set forth below. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Entities

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

CPPIB means the Canada Pension Plan Investment Board.

Shareholders mean holders of our Common Shares.

TORC, **we**, **us**, **our** or the **Corporation** means TORC Oil & Gas Ltd.

Vero means Vero Energy Inc.

Villanova means Villanova 4 Oil Corp.

Independent Engineering

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.

NI 51-101 means National Instrument 51 101 – *Standards of Disclosure for Oil and Natural Gas Activities* of the Canadian Securities Administrators.

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the independent engineering report dated February 27, 2020 and effective December 31, 2019 prepared by Sproule evaluating the oil, NGL and natural gas reserves attributable to all of our properties.

Securities

Common Shares means our common shares, as presently constituted.

Preferred Shares means our first preferred shares issuable in series.

Other

2017 August Acquisition means the acquisition of the 2017 August Acquisition Assets by us on August 1, 2017.

2017 August Acquisition Assets means the light oil producing assets located in the Cardium area that were acquired by us pursuant to the 2017 August Acquisition.

2017 October Acquisition means the acquisition of the 2017 October Acquisition Assets by us on October 1, 2017.

2017 October Acquisition Assets means the light oil producing assets located in southeast Saskatchewan that were acquired by us pursuant to the 2017 October Acquisition.

2017 Q2 Net Acquisition means the acquisition of the 2017 Q2 Net Acquisition Assets by us in the second quarter of 2017.

2017 Q2 Net Acquisition Assets means the light oil assets located in southeast Saskatchewan that were acquired by us pursuant to the 2017 Q2 Net Acquisition.

2017 Q4 Net Acquisitions means the three acquisitions of the 2017 Q4 Net Acquisitions Assets by us in the fourth quarter of 2017.

2017 Q4 Net Acquisitions Assets means the light oil producing assets located in southeast Saskatchewan that were acquired by us pursuant to the 2017 Q4 Net Acquisitions.

2018 Q2 Acquisition means the acquisition of the 2018 Q2 Acquisition Assets by us in the second quarter of 2018.

2018 Q2 Acquisition Assets means the light oil assets located in southeast Saskatchewan that were acquired by us pursuant to the 2018 Q2 Acquisition.

2018 V4 Acquisition means the acquisition of Villanova, a private oil company with complementary high quality, light oil assets in southeast Saskatchewan.

ABCA means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B 9, as amended, including the regulations promulgated thereunder.

Credit Facility means our $500 million credit facility. See *Capital Structure* for further information on our Credit Facility.

ABBREVIATIONS AND CONVERSIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

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

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
$000s or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of our natural gas and petroleum reserves does not represent the fair market value of our reserves.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means barrel of oil equivalent on the basis of 1 Bbl to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 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 to 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in NI 51-101, CSA 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 or the COGE Handbook.

Reserves

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, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

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

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

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

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

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

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

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

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

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

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

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

Interests in Reserves, Production, Wells and Properties

gross means: (a) in relation to our interest in production or reserves, our "company gross reserves", which are our working interest (operating or 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.

net means: (a) in relation to our interest in production or reserves our working interest (operating or non-operating) share after deduction of royalty obligations, plus our royalty interests in production or reserves; (b) in relation to our interest in 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.

working interest means the percentage of undivided interest held by us in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives us the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

development costs means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the 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, 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.

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

exploration costs means 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 natural 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 (sometimes referred to in part as **prospecting costs**) 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 (collectively sometimes referred to as **geological and geophysical costs**); (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.

exploration well means a well that is not a development well, a service well or a stratigraphic test well.

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 or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. More particularly, this Annual Information Form contains forward-looking statements with respect to:

- various matters with respect to our 2020 capital budget;
- our corporate strategy, plans and objectives;
- the anticipated impact of environmental laws and regulations on us;
- our environmental, health, safety and sustainability plans;
- the impact of seasonal factors on us;
- the impact of the renegotiation or termination of contracts on our business;
- our plans for the development of our proved and probable undeveloped reserves;
- the impact of economic factors or uncertainties on our properties with no attributed reserves;
- our anticipated land expiries;
- our plans for funding future development costs;
- anticipated future abandonment and reclamation costs;
- our expectations of the means of funding our ongoing environmental obligations;
- income tax estimates and our tax horizon;
- our dividend policy and dividend funding requirements;
- the next scheduled review of the borrowing base of our Credit Facility; 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 can be profitably produced in the future.

The forward-looking statements are based on certain key expectations and assumptions made by us, including, but not limited to:

- oil and natural gas production levels;
- commodity prices, differentials and exchange rates;
- prevailing weather conditions;
- availability of labour, services and equipment;
- timing and amount of capital expenditures;
- general economic and financial market conditions;
- government regulation in the areas of production curtailment, taxation, royalty rates and environmental protection; and
- the success of our exploration and development activities.

Although we believe that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because we can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to:

- the impact of COVID-19;
- volatility in commodity prices and differentials;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services and equipment on a timely basis or favourable terms;
- competition for, among other things, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, production and processing problems;
- availability and cost of capital;
- changes in legislation, including changes in tax laws, royalty rates, production curtailment and incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under *Risk Factors*.

The payment and the amount of dividends declared in any month will be subject to the discretion of our Board of Directors and will depend on our Board of Directors' assessment of our outlook for growth, capital expenditure requirements, funds from operations, potential acquisition opportunities, debt position and other conditions that our Board of Directors may consider relevant at such future time. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including fluctuations in commodity prices and differentials, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

NON-GAAP MEASURES

This Annual Information Form contains the term "netback" which does not have a standardized meaning under generally accepted accounting principles in Canada and therefore may not be comparable with the calculation of similar measures by other companies. We use netback to analyze our financial and operating performance. Netback is not intended to represent operating profits nor should it be viewed as an alternative to net earnings or other measures of financial performance calculated in accordance with generally accepted accounting principles in Canada. In this Annual Information Form, netback is determined by deducting royalties, operating expenses and transportation expenses from oil and gas revenue.

TORC OIL & GAS LTD.

General

We are the resulting entity following the completion of the reverse takeover of Vero and subsequent amalgamation with 1688763 Alberta Ltd. and Vero on November 19, 2012 to form "TORC Oil & Gas Ltd.".

Vero was initially formed on November 2, 2005 upon the amalgamation of Vero Energy Inc. and its then wholly-owned subsidiary, Vero Finance Corp. under the ABCA. On January 1, 2010, Vero amalgamated with its then wholly-owned subsidiary, Vero Oil and Gas Ltd.

1525893 Alberta Ltd. was incorporated on March 23, 2010 under the ABCA. On December 15, 2010, we filed articles of amendment changing our name from 1525893 Alberta Ltd. to "TORC Oil & Gas Ltd.". On the same day, we amended our articles to remove: (i) certain restrictions upon invitations to the public to subscribe for our shares; and (ii) restrictions limiting the number of shareholders, exclusive of employees, to less than 50 shareholders. On January 24, 2011, we filed articles of amendment to remove certain restrictions on the transfer of our shares.

On May 1, 2011, we amalgamated with our then wholly-owned subsidiary, Shale Exploration Ltd., with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

On November 19, 2012, we amalgamated with 1688763 Alberta Ltd. and Vero pursuant to a plan of arrangement under the ABCA, with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

On September 10, 2013, we filed articles of amendment to consolidate our Common Shares on the basis of one Common Share for every five pre-consolidated common shares.

On February 25, 2015, certain private companies acquired by us in 2015 were amalgamated into us, with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

On July 26, 2018, 2126046 Alberta Ltd. and Villanova amalgamated to form "TORC Acquisition Corp.", TORC Acquisition Corp. was then amalgamated into us, with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

Head Office and Registered Office

Our head office is located at 1800, 525 – 8th Avenue S.W., Calgary, Alberta. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta.

Stock Exchange and Reporting Issuer Status

Our Common Shares are listed for trading on the Toronto Stock Exchange under the symbol "TOG". We are a reporting issuer in each of the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland.

Intercorporate Relationships

We have no material subsidiaries.

DEVELOPMENT OF OUR BUSINESS

History and Development

The following is a summary of how our business has developed over the last three years.

Developments in 2017

On April 4, 2017, we completed the 2017 Q2 Net Acquisition, along with the disposition of certain minor non-core assets in our southeast Saskatchewan core area. Net of the non-core disposition, total consideration paid was $9.8 million in cash and the issuance of 2.8 million Common Shares. The 2017 Q2 Net Acquisition added approximately 650 BOE/d of light oil producing assets (86% light oil, 4% NGLs and 10% conventional natural gas).

On August 1, 2017, we completed the 2017 August Acquisition. The strategic acquisition included approximately 100 BOE/d of light oil producing assets (71% light oil, 2% NGLs and 27% conventional natural gas). Net cash consideration paid was $5.3 million.

On October 1, 2017, we completed the 2017 October Acquisition for cash consideration of $15 million. The 2017 October Acquisition included approximately 200 BOE/d of light oil producing assets (100% light oil) located in our core operating area in southeast Saskatchewan.

On October 31, 2017, the Credit Facility was reconfirmed at $400 million.

In the fourth quarter of 2017, we completed the 2017 Q4 Net Acquisitions along with two minor non-core asset dispositions. The net production addition was approximately 900 BOE/d (92% light oil, 3% NGLs and 5% conventional natural gas) for aggregate consideration comprised of the issuance of 5.8 million Common Shares and $25.0 million in cash. The majority of the 2017 Q4 Net Acquisitions Assets are located in our core operating area in southeast Saskatchewan. The 2017 Q4 Net Acquisitions Assets also included a strategic top-up acquisition in the Cardium play.

Developments in 2018

On January 23, 2018, Mary-Jo Case was appointed to our Board.

Subsequent to the first quarter of 2018, we entered into a purchase and sale agreement with an independent Canadian oil and gas company, dated May 8, 2018, to acquire the 2018 Q2 Acquisition Assets for consideration comprised of the issuance of 13.5 million Common Shares and $125.0 million in cash, prior to customary closing adjustments. The 2018 Q2 Acquisition Assets included over 3,200 BOE/d of high quality, low decline, high netback, light oil producing assets (100% light oil).

On May 8, 2018, we announced that our Board had approved a 10% increase to our annual dividend to $0.022 per Common Share effective June 15, 2018.

On June 27, 2018, we completed the previously announced 2018 Q2 Acquisition and we expanded our Credit Facility to $500 million from $400 million.

On July 26, 2018, we completed the 2018 V4 Acquisition for the issuance of 2.1 million Common Shares and $46.5 million in cash, prior to customary closing adjustments. The 2018 V4 Acquisition included over 1,000 BOE/d (70% light oil, 11% NGLs and 19% conventional natural gas) of high netback, light oil producing assets primarily focused in the emerging unconventional Midale play.

On November 5, 2018, John Gordon was appointed to our Board.

Developments in 2019

On December 11, 2018, we announced that our Board had approved our 2019 capital budget of $180 million. Our 2019 capital program was focused on light oil development projects, with the majority of the capital directed to drilling, completions and tie-ins (approximately 75%), and with the remainder allocated to operational and facility optimization to maximize production efficiency. The capital program was concentrated on our primary core areas in southeast Saskatchewan, focused on both conventional and unconventional opportunities, along with the Cardium play in central Alberta.

On May 7, 2019, we announced that our Board had approved a 14% increase to our annual dividend to $0.025 per Common Share effective May 15, 2019.

On May 7, 2019, we announced that Raymond Chan was retiring from our Board and was not standing for re-election at the 2019 annual Shareholders' meeting held on May 8, 2019.

On December 11, 2019, Catharine M. de Lacy was appointed to our Board.

Recent Developments

On December 11, 2019, we announced that our Board had approved our 2020 capital budget of $190 million. Our 2020 capital program is focused on light oil development projects, with the majority of the capital directed to drilling, completions and tie-ins (approximately 70%), with the remainder allocated to operational and facility optimization, expansion of infrastructure, gas conservation projects and inactive well retirements. The capital program is concentrated on our primary core areas in southeast Saskatchewan, focused on both conventional and unconventional opportunities, along with the Cardium play in central Alberta.

In March 2020, weakness in commodity prices and reduced global economic activity following the outbreak of the novel coronavirus ("**COVID-19**") caused us to announce that we expect to defer, reallocate and reduce capital in the second half of the year as current business conditions persist. We also announced a reduction in our monthly dividend per Common Share from $0.025 per month to $0.005 per month.

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*.

DESCRIPTION OF OUR BUSINESS

Corporate Strategy

We are an intermediate light oil producer paying dividends while also pursuing cost-effective per share growth in reserves, production and revenues in western Canada.

Our overall corporate strategy is to provide cost-effective per share growth in reserves, production, and revenues combined with a sustainable monthly dividend by:

- focusing on high quality, light oil weighted plays;
- positioning us for growth through exposure to light oil assets utilizing an integrated strategy of resource capture, delineation and development;
- maintaining a strong balance sheet; and
- attracting and retaining top quality technical and corporate staff with proven track records.

Ongoing Acquisitions and Disposition Activities

Our Board may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the strategy discussed above based upon its consideration of the qualitative aspects of the proposed acquisition, including risk profile, technical upside, reserve life, strategic importance and asset quality. See *Industry Conditions* and *Risk Factors*.

Competition

The oil and natural gas industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of oil and natural gas assets and in the marketing of oil and natural gas. Competitive factors in the distribution and marketing of oil and natural gas include price coupled with methods and reliability of delivery. We believe that our competitive position is equivalent to that of other oil and natural gas issuers of similar size, comparable capital structure and at a similar stage of development. See *Industry Conditions* and *Risk Factors*.

Environmental Policies

We support environmental protection and employee health and safety by integrating the essential principles and practices through our environmental management systems and employee occupational health and safety programs. 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 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 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. See *Industry Conditions* and *Risk Factors*.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2019, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, and gathering systems and processing facilities totaled $2.8 million. See *Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs* for further information.

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, health, safety and sustainability ("EHS&S"). In recognition of the importance of clear board oversight and risk management for EHS&S matters, we have established a separate EHS&S Committee of our Board.

We have outlined key highlights of our corporate responsibilities pertaining to environment, health and safety, and governance initiatives on our website under "Corporate Responsibility". You will see our high safety performance, our current emissions operations, our proactive asset integrity program and replacement of aging assets and our strong governance and community focus. We continue to execute projects to enhance our EHS&S progress, and we look forward to providing updated EHS&S reporting in the future.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can also have a significant negative impact on our operations and costs. See *Industry Conditions* and *Risk Factors*.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2020 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2019, we had 81 head office employees and 25 field employees.

PRINCIPAL 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. **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.**

West Central Alberta Cardium

Our West Central Alberta Cardium properties consist of an average working interest of approximately 72% in 214,943 gross (154,524 net) acres of land in the Brazeau, Carrot Creek, Kaybob, Pembina, Pine Creek and Rosevear areas on the Cardium trend in west central Alberta, all of which are located approximately 150 to 250 kilometres west of Edmonton. In 2019, we targeted the Cardium formation, drilling a total of 8 gross (6.8 net) oil wells.

The properties include 174 gross (143 net) producing light oil wells and 17 gross (8 net) producing gas wells. We operate two major oil production facilities in the Kaybob and Pembina fields. Average daily production from the properties for the year ended December 31, 2019 was 4,866 BOE/d. Production consisted of 439 Bbls/d of NGLs, 2,777 Bbls/d of light and medium crude oil and 9,896 Mcf/d of conventional natural gas. As at December 31, 2019, the Sproule Report attributed proved plus probable reserves of 19,971 Mbbls of light oil and NGLs and 84,404 MMcf of natural gas to the Cardium properties.

Southeast Saskatchewan and Manitoba

Our southeast Saskatchewan and Manitoba assets consist of an average working interest of approximately 80% in 491,875 gross (391,577 net) acres of land primarily focused on conventional Mississippian light oil plays and the Torquay/Three Forks and Midale unconventional light oil resource plays. In 2019, we targeted the Frobisher formations in drilling a total of 47 gross (35.0 net) conventional light oil wells. Additionally in 2018, we targeted the Torquay/Three Forks and Midale formations in drilling a total of 13 gross (12.0 net) and 18 gross (14.7 net) unconventional light oil wells, respectively.

The southeast Saskatchewan and Manitoba assets include 2,310 gross (1,316 net) producing light oil wells. Major facilities include operated oil production facilities at Flat Lake, Openshaw, Steelman, Wapella, Weir Hill and Willmar. Average daily production from the properties for the year ended December 31, 2019 was 23,270 BOE/d. Production consisted of 1,117 Bbls/d of NGLs, 20,538 Bbls/d of light and medium crude oil and 9,692 Mcf/d of conventional natural gas. As at December 31, 2019, the Sproule Report attributed proved plus probable reserves of 95,465 Mbbls of light oil and NGLs and 46,884 MMcf of natural gas to the southeast Saskatchewan and Manitoba properties.

STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below is dated February 27, 2020. The statement is effective as of December 31, 2019 and the preparation date of the statement is February 27, 2020. The Report on Reserves Data By Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors On Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules "B" and "C" to this Annual Information Form.

In accordance with NI 51-101, Sproule prepared the Sproule Report. The Sproule Report evaluated, as at December 31, 2019, all of our crude oil, NGL and natural gas reserves.

The tables below are a summary of our crude oil, NGLs and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to our reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs. The reserve assessments also include costs associated with wells that have not been assessed values in the reserve reports and facilities and gathering systems. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to our reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided.

We determined the future net revenue and present value of future net revenue after income tax expenses by utilizing Sproule's before income tax future net revenue 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 attributes 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 the value of us 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 taxes.

The Sproule Report is based on certain factual data supplied by us and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by us to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

	RESERVES							
	GROSS RESERVES				NET RESERVES			
RESERVE CATEGORY	Light and Medium Crude Oil	Natural Gas Liquids	Conven-tional Natural Gas	Total BOE	Light and Medium Crude Oil	Natural Gas Liquids	Conven-tional Natural Gas	Total BOE
	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)
PROVED:								
Developed Producing	44,176	3,641	46,000	55,484	39,523	3,174	41,893	49,679
Developed Non-Producing	1,750	172	2,830	2,394	1,560	144	2,499	2,120
Undeveloped	25,451	2,065	32,700	32,966	23,386	1,848	29,804	30,201
TOTAL PROVED	71,377	5,878	81,530	90,844	64,469	5,166	74,196	82,001
PROBABLE	37,404	3,197	49,758	48,894	33,383	2,778	44,772	43,623
TOTAL PROVED PLUS PROBABLE	108,781	9,075	131,288	139,739	97,852	7,945	118,968	125,624

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)					
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% per Year(1) ($/BOE)
PROVED:						
Developed Producing	1,253,739	1,196,197	1,040,791	912,966	814,690	20.95
Developed Non-Producing	59,454	46,264	37,463	31,276	26,721	17.67
Undeveloped	704,014	472,222	321,646	221,911	153,346	10.65
TOTAL PROVED	2,017,207	1,714,682	1,399,900	1,166,153	994,757	17.07
PROBABLE	1,663,853	1,031,532	716,075	533,022	416,004	16.41
TOTAL PROVED PLUS PROBABLE	3,681,060	2,746,214	2,115,975	1,699,175	1,410,761	16.81

Note:

(1) Unit values are based on net volumes.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,253,739	1,196,197	1,040,791	912,966	814,690
Developed Non-Producing	59,454	46,263	37,463	31,275	26,721
Undeveloped	531,528	352,870	235,671	157,921	104,424
TOTAL PROVED	1,844,721	1,595,330	1,313,925	1,102,162	945,835
PROBABLE	1,261,916	763,320	522,800	386,005	299,765
TOTAL PROVED PLUS PROBABLE	3,106,637	2,358,650	1,836,725	1,488,167	1,245,600

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS (1)(2)								
RESERVES CATEGORY	**REVENUE ($000s)**	**ROYALTIES ($000s)**	**OPERATING COSTS ($000s)**	**DEVELOPMENT COSTS ($000s)**	**ABANDONMENT AND RECLAMATION COSTS (3) ($000s)**	**FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES ($000s)**	**INCOME TAX EXPENSES ($000s)**	**FUTURE NET REVENUE AFTER INCOME TAX EXPENSES ($000s)**
Total Proved	6,382,259	753,181	2,420,328	673,080	518,463	2,017,207	172,486	1,844,721
Total Proved plus Probable	10,123,353	1,220,776	3,698,817	981,411	541,288	3,681,060	574,423	3,106,637

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include crown, freehold and overriding royalties, mineral tax and Saskatchewan Capital Surtax.
(3) These are estimated abandonment and reclamation costs for all active and inactive wells, including costs for producing wells, suspended wells, service wells, gathering systems, facilities, and surface land development.

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS			
RESERVES CATEGORY	**PRODUCTION GROUP**	**FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)**	**UNIT VALUE (1)**
			($/Bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	1,445,218	17.75
	Conventional Natural Gas (3)	1,590	2.66
	Other Items (4)	(46,908)	
	Total	1,399,900	
Proved plus Probable	Light and Medium Crude Oil (2)	2,158,809	17.36
	Conventional Natural Gas (3)	4,075	3.18
	Other Items (4)	(46,908)	
	Total	2,115,975	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products
(3) Including by-products but excluding solution gas and by-products from oil wells.
(4) "Other Items" include Alberta Capital gas cost allowance, select scheduled abandonment and reclamation costs, and other items.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following Sproule price forecast, which consists of pricing, exchange rate and inflation rate assumptions as of December 31, 2019 in the Sproule Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2019 are also reflected in the table below.

	SUMMARY OF WEIGHTED AVERAGE HISTORICAL PRICES FOR 2019 AND PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS (1)								
	MEDIUM AND LIGHT CRUDE OIL			NATURAL GAS	NATURAL GAS LIQUIDS				
YEAR	WTI Cushing Oklahoma 40° API ($US/Bbl)	Edmonton Par Price 40° API ($/Bbl)	Cromer LSB 35° API ($/Bbl)	AECO-C Spot ($/MMBtu)	Edmonton Butane ($/Bbl)	Pentanes Plus ($/Bbl)	Capital Cost Inflation Rate (%/Yr) (2)	Operating Cost Inflation Rate (%/Yr) (2)	Exchange Rate ($US/$) (3)
2019 Actual	57.02	68.87	69.68	1.80	23.71	71.39	0.7%	-0.6%	0.75
2020	61.00	73.84	73.84	2.04	37.72	76.32	0.0%	0.0%	0.76
2021	65.00	78.51	77.51	2.27	43.90	80.52	1.0%	1.0%	0.77
2022	67.00	78.73	77.73	2.81	47.74	80.00	2.0%	2.0%	0.80
2023	68.34	80.30	79.30	2.89	48.69	81.68	2.0%	2.0%	0.80
2024	69.71	81.91	80.91	2.98	49.67	83.38	2.0%	2.0%	0.80
2025	71.10	83.54	82.54	3.06	50.66	85.13	2.0%	2.0%	0.80
2026	72.52	85.21	84.21	3.15	51.67	86.90	2.0%	2.0%	0.80
2027	73.97	86.92	85.92	3.24	52.71	88.72	2.0%	2.0%	0.80
2028	75.45	88.66	87.66	3.33	53.76	90.57	2.0%	2.0%	0.80
2029	76.96	90.43	89.43	3.42	54.84	92.45	2.0%	2.0%	0.80
2030	78.50	92.24	91.24	3.51	55.93	94.38	2.0%	2.0%	0.80

Escalated at 2.0% per year thereafter

Notes:

(1) As at January 1, 2020.
(2) Inflation rates for forecasting costs only. Prices inflated at 2% where applicable.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2019, derived from the Sproule Report using forecast prices and cost estimates, reconciled to our gross reserves as at December 31, 2018.

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS				
PROVED RESERVES	**LIGHT AND MEDIUM CRUDE OIL**	**NATURAL GAS LIQUIDS**	**CONVENTIONAL NATURAL GAS**	**TOTAL OIL EQUIVALENT**
	(Mbbls)	**(Mbbls)**	**(MMcf)**	**(MBOE)**
December 31, 2018	70,757	5,697	83,036	90,294
Extensions (1)	2,924	205	2,391	3,528
Infill Drilling (1)	1,054	27	181	1,111
Improved Recovery	16	-	-	16
Technical Revisions (2)	5,965	629	5,122	7,448
Discoveries	-	-	-	-
Acquisitions (3)	875	53	765	1,055
Dispositions	(237)	-	-	(237)
Economic Factors	(1,396)	(165)	(2,816)	(2,031)
Production	(8,580)	(568)	(7,150)	(10,339)
December 31, 2019	71,378	5,878	81,531	90,845

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS				
PROBABLE RESERVES	**LIGHT AND MEDIUM CRUDE OIL**	**NATURAL GAS LIQUIDS**	**CONVENTIONAL NATURAL GAS**	**TOTAL OIL EQUIVALENT**
	(Mbbls)	**(Mbbls)**	**(MMcf)**	**(MBOE)**
December 31, 2018	**36,776**	**3,100**	**50,468**	**48,288**
Extensions (1)	1,929	85	1,154	2,206
Infill Drilling (1)	912	15	105	944
Improved Recovery	15	-	-	15
Technical Revisions (2)	(2,418)	44	(834)	(2,513)
Discoveries	-	-	-	-
Acquisitions (3)	461	27	361	548
Dispositions	(69)	-	-	(69)
Economic Factors	(202)	(74)	(1,496)	(525)
Production	-	-	-	-
December 31, 2019	**37,404**	**3,197**	**49,758**	**48,894**

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS				
PROVED PLUS PROBABLE RESERVES	**LIGHT AND MEDIUM CRUDE OIL**	**NATURAL GAS LIQUIDS**	**CONVENTIONAL NATURAL GAS**	**TOTAL OIL EQUIVALENT**
	(Mbbls)	**(Mbbls)**	**(MMcf)**	**(MBOE)**
December 31, 2018	**107,533**	**8,798**	**133,504**	**138,582**
Extensions (1)	4,853	291	3,545	5,734
Infill Drilling (1)	1,966	41	287	2,055
Improved Recovery	31	-	-	31
Technical Revisions (2)	3,547	673	4,288	4,935
Discoveries	-	-	-	-
Acquisitions (3)	1,336	80	1,126	1,603
Dispositions	(306)	-	-	(306)
Economic Factors	(1,598)	(240)	(4,312)	(2,556)
Production	(8,580)	(568)	(7,150)	(10,339)
December 31, 2019	**108,782**	**9,075**	**131,288**	**139,739**

Notes:

(1) The extensions and infill drilling amounts include all new wells drilled and booked during the year as a result of our development activity. We continued to develop our light oil assets in the Cardium resource play in Alberta and our Midale and Torquay/Three Forks resource plays and conventional Mississippian assets in the Williston Basin.

(2) The technical revisions amount includes all changes in previously booked reserves due to the performance of existing wells and those drilled during the year. The positive proved plus probable technical revision is a result of improvements in oil well performance, implementation of new solution gas conservation projects, improved natural gas and NGL recoveries on existing projects and successful waterflood optimization projects. Negative technical revisions on probable reserve volumes are reflective of reserve volumes being transferred to the proved reserves category as a result of increased reserves confidence due to offset well performance and drilling activity during the current year.

(3) The acquisitions amount is the estimate of reserves at December 31, 2019 plus any production since the acquisition dates.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

All of our undeveloped reserves are located in our core areas where we actively spend capital each year to develop the reserves. We currently plan to pursue the development of a large majority of our proved and probable undeveloped reserves within the next three years and substantially all of our currently booked development projects within the next five years through ordinary course capital expenditures. The exception to this is our non-operated Weyburn Unit property which will require approximately ten years to complete the development of the asset due to the longer term nature of carbon dioxide miscible floods. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) 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 gross proved undeveloped reserves that were attributed in each of the most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2017	4,526	19,761	3,797	28,866	348	1,593
2018	4,972	25,137	6,106	34,572	526	2,091
2019	2,354	25,451	1,381	32,700	103	2,065

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. Sproule has assigned 33.0 MMboe of gross proved undeveloped reserves in the Sproule Report with $646.1 million of associated undiscounted future development capital, of which $330.6 million is forecast to be spent in the first two years.

Probable Undeveloped Reserves

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

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2017	4,783	18,151	5,804	31,168	357	1,540
2018	5,083	21,156	4,385	37,336	343	1,970
2019	2,493	21,432	1,120	35,103	80	1,929

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. Sproule has assigned 29.2 MMboe of gross probable undeveloped reserves in the Sproule Report with $302.1 million of associated undiscounted future development capital, of which $68.7 million is forecast to be spent in the first two years.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under *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. Our reserves can also be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that are beyond our control. See *Risk Factors*.

Abandonment, Decommissioning and Reclamation Costs

Commencing in 2019, Sproule included additional abandonment, decommissioning and reclamation obligations ("**ADR**") in our reserves evaluation, which resulted in a decrease in value relative to 2018. This change to the prior years' practices, which were consistent with the reporting of many other companies in the industry, was made based on new guidelines contained within the COGE Handbook, which recommends adopting the best practice of including ADR costs associated with all of our assets evaluated in the Sproule Report. This includes costs for both active and inactive wells, including ADR costs for producing wells, suspended wells, service wells, gathering systems, facilities, and surface land development for all our assets. These costs were estimated considering: (i) provincial regulatory guidance; (ii) recent industry abandonment and reclamation practices, developments and experiences; and (iii) specific well and infrastructure characteristics, including type, depth, age, and any site specific matters. Actual costs may differ from estimated costs due to changes in laws and regulations, timing of costs, changes in technology and market conditions. We review suspended or standing wellbores for reactivation, recompletion or sale and conduct systematic abandonment programs for those wellbores that are no longer required. A portion of our liabilities are retired each year and facilities are typically decommissioned when all of the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, environmental risk, stakeholder issues, and opportunities for multi-location programs to reduce costs.

At year-end 2019, Sproule's evaluation of the costs (discounted at 10%) for ADR related to our proved plus probable, proved, and proved developed producing reserves was $69.1 million, $68.9 million, and $66.7 million, respectively, an increase of $38.6 million, $32.6 million, and $35.7 million compared to the corresponding ADR measures in the 2018 evaluation.

Sproule included total ADR costs under the proved reserves category of $518.5 million undiscounted ($68.9 million discounted at 10%) in the Sproule Report, $17.1 million of which is expected to be incurred from 2020 to 2023. Sproule included total ADR costs under the total proved plus probable reserves category of $541.3 million undiscounted ($69.1 million discounted at 10%) in the Sproule Report, $17.1 million of which is expected to be incurred from 2020 to 2023.

The above well abandonment and reclamation costs from the Sproule Report include $39.7 million undiscounted ($2.2 million discounted at 10%) for 333 net (414 gross) future proved development locations and $62.4 million undiscounted ($2.4 million discounted at 10%) for 361 net (448 gross) future proved plus probable development locations.

The future net revenues disclosed in this Annual Information Form based on the Sproule Report do not contain an allowance for salvage.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to our proved reserves and proved plus probable reserves (using forecast prices and costs).

Year	FORECAST PRICES AND COSTS	
	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2020	153,736	186,419
2021	186,278	223,104
2022	186,684	268,097
2023	120,794	235,456
Remainder	25,588	68,335
TOTAL UNDISCOUNTED	673,080	981,411

We have three sources of funding available to finance future development costs: internally generated funds from operations, debt financing and equity financing. We ordinarily expect to fund future development costs primarily through funds from operations, but may rely, to some extent, on debt financing by drawing down on our Credit Facility or equity financing by issuing additional securities depending on prevailing commodity prices, market conditions, the desirability of accelerating our capital expenditure program and the availability of financing on favourable terms.

In March of 2020, we announced a review of our 2020 capital budget which may be below the 2020 development costs in the Sproule 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 Sproule 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 these reserves and future net revenue to some degree depending upon the funding sources utilized. The cost of the debt component for funding future development costs is expected to be minimal and to not materially impact the disclosed reserves or future net revenue.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of our wells effective December 31, 2019.

	PRODUCING WELLS				NON-PRODUCING WELLS			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	192	161	17	8	142	118	9	4
Saskatchewan	2,198	1,211	-	-	576	451	-	-
Manitoba	112	106	-	-	26	26	-	-
TOTAL	2,502	1,477	17	8	744	595	9	4

Note:

(1) Gross and net producing and non-producing oil and gas well counts include both reserve assigned and non-reserve assigned wells.

Non-producing wells are generally situated within defined developed areas and include recent drills awaiting final preparation prior to being placed on production; existing wells that may be waiting on improved economic conditions to restart; wells currently in use for observation or monitoring; wells awaiting recompletion in secondary zones or as injectors; or wells scheduled for abandonment. These non-producing entities include wells with reserve assignments as well as currently non-booked wells, which will have various terms of being non-producing from recent to longer-term. Wells in the non-producing reserves category represent less than 15% of total non-producing well count on a net basis and exist across most of our areas and mostly represent wells awaiting final preparation for production and wells with secondary producing zones that continue to produce out of the primary zone. These non-producing wells are not impacted by proximity of pipelines.

Undeveloped Land

The following table summarizes, effective December 31, 2019, the gross and net acres of undeveloped properties in which we had an interest and also the number of net acres for which our rights to explore, develop or exploit could expire within one year.

	GROSS ACRES	NET ACRES	NET ACRES EXPIRING WITHIN ONE YEAR
Alberta	187,088	139,568	5,656
Saskatchewan	224,427	179,314	29,479
Manitoba	8,740	8,740	2,952
TOTAL	420,255	327,622	38,088

Note:

(1) In limited circumstances, we may hold interests in different formations under the same surface area pursuant to separate leases. In such circumstances each lease is counted separately as to both the gross and net acres reported.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2019, the gross and net acres of properties with no reserves assigned in which we had an interest and also the number of net acres for which our rights to explore, develop or exploit could expire within one year.

	GROSS ACRES	NET ACRES	NET ACRES EXPIRING WITHIN ONE YEAR
Alberta	169,207	124,689	5,656
Saskatchewan	206,031	157,306	29,479
Manitoba	8,506	8,506	2,952
TOTAL	383,744	290,501	38,088

Note:

(1) In limited circumstances, we may hold interests in different formations under the same surface area pursuant to separate leases. In such circumstances each lease is counted separately as to both the gross and net acres reported.

Significant Factors or Uncertainties Relevant to 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. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See *Additional Information Relating to Reserves Data – Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs* and *Risk Factors*.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us from time to time to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

At December 31, 2019, we had outstanding financial derivative commitments for crude oil. For more details, see Note 22 to our 2019 annual audited financial statements.

Tax Horizon

Based on Sproule production forecasts, planned capital expenditures and the forecast commodity pricing employed in the Sproule Report, we estimate that we will not be required to pay current income taxes until at least 2025.

Costs Incurred

The following table summarizes capital expenditures incurred by us during the year ended December 31, 2019.

	PROPERTY ACQUISITION COSTS			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
TOTAL (millions)	$6.7	$nil	$nil	$180.0

Exploration and Development Activities

We drilled 86 gross (68.5 net) light and medium crude oil development wells in 2019. All of these wells were drilled in Canada. We did not drill any other wells in 2019.

Planned Capital Expenditures

In December 2019 we announced our planned capital expenditure budget of $190 million for 2020 which is primarily focused on light oil development projects with the majority of the capital directed to drilling, completions and tie-ins (greater than 80%) with the remainder allocated to operational and facility optimization to maximize production efficiency. This capital budget includes drilling 44 gross (34.2 net) conventional wells in southeast Saskatchewan, 13 gross (12 net) wells in the Torquay/Three Forks, 17 (14.8 net) wells in the unconventional Midale, and 8 gross (6.7 net) wells across our land position in the Cardium.

On March 16, 2020, we announced that we were reviewing capital spending for the remainder of the year given ongoing global events and expect to defer, reallocate and reduce capital in the second half of the year as current business conditions persist.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Sproule Report for 2020 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)	Percentage (%)
PROVED					
Alberta	3,119	497	11,009	5,451	19%
Saskatchewan	18,751	1,272	10,918	21,842	76%
Manitoba	1,445	-	-	1,445	5%
TOTAL PROVED	**23,315**	**1,769**	**21,926**	**28,738**	**100%**
PROVED PLUS PROBABLE					
Alberta	3,414	519	11,511	5,852	19%
Saskatchewan	20,873	1,425	12,320	24,351	77%
Manitoba	1,602	-	-	1,602	24%
TOTAL PROVED PLUS PROBABLE	**25,890**	**1,944**	**23,831**	**31,805**	**100%**

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2019, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback.

	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)	23,700	23,534	23,382	23,415	23,507
Natural Gas Liquids (Bbls/d)	1,459	1,559	1,587	1,616	1,556
Conventional Natural Gas (Mcf/d)	18,646	19,397	20,206	20,079	19,588
Combined (BOE/d)	28,267	28,326	28,337	28,378	28,328
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	64.85	70.03	64.65	63.05	65.64
Natural Gas Liquids ($/Bbl)	20.32	12.28	11.91	12.71	14.16
Conventional Natural Gas ($/Mcf)	2.18	0.67	0.75	2.07	1.41
Combined ($/BOE)	56.86	59.32	54.55	54.22	56.22
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	11.45	12.38	10.97	10.51	11.32
Natural Gas Liquids ($/Bbl)	3.59	2.17	2.02	2.12	2.44
Conventional Natural Gas ($/Mcf)	0.39	0.12	0.13	0.35	0.24
Combined ($/BOE)	10.04	10.49	9.25	9.04	9.70
Production Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	16.17	17.10	17.07	16.65	16.75
Natural Gas Liquids ($/Bbl)	5.07	3.00	3.15	3.36	3.61
Conventional Natural Gas ($/Mcf)	0.54	0.16	0.20	0.55	0.36
Combined ($/BOE)	14.18	14.48	14.40	14.32	14.34
Netback Received (4)					
Light and Medium Crude Oil ($/Bbl)	37.23	40.55	36.61	35.89	37.57
Natural Gas Liquids ($/Bbl)	11.66	7.11	6.74	7.23	8.11
Conventional Natural Gas ($/Mcf)	1.25	0.39	0.42	1.17	0.81
Combined ($/BOE)	32.64	34.35	30.90	30.86	32.18

Notes:

(1) Before the deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and 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 production costs and accounted for as a reduction to general and administrative costs.

(4) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received. See *Non-GAAP Measures*.

Production Volume by Field

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

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)	Percentage (%)
Alberta	2,969	439	9,896	5,057	18
Saskatchewan	18,960	1,117	9,692	21,693	76
Manitoba	1,578	-	-	1,578	6
TOTAL	23,507	1,556	19,588	28,328	100

CAPITAL STRUCTURE

Credit Facility

Our Credit Facility is a $500 million reserves-based revolving credit facility, comprised of a $55 million operating facility from our operating lender (the "**Operating Facility**") and a $445 million syndicated facility with a syndicate of banks (the "**Syndicated Facility**"). Advances under the Credit Facility are available by way of direct advances, bankers' acceptances and standby letters of credit/guarantees. Direct advances bear interest at the prime rate, U.S. base rate or Libor rate, as applicable, plus a margin which is dependent on our debt to trailing funds flow ratio. The bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a stamping fee, based on our debt to trailing funds flow ratio.

Both the Syndicated Facility and the Operating Facility are available on a revolving basis until April 30, 2020. On or before April 30, 2020, at our request and subject to the approval of the lending syndicate, the Credit Facility may be extended for an additional 364 day period. In the event of non-extension, the undrawn portion of the Credit Facility will be cancelled and the amount outstanding will convert to a 364 day non-revolving term facility with repayment of the Credit Facility due on April 30, 2021. The Credit Facility is secured by a fixed and floating charge debenture on all of our assets.

The borrowing base of our Credit Facility is primarily based on reserves and commodity prices estimated by the lenders. The borrowing base of our Credit Facility is subject to review and redetermination by the lenders on a semi-annual basis and in the event of a change in our borrowing base properties (including due to a disposition of assets beyond certain defined limits or a change which results in a material adverse effect, as determined by the lenders). In the normal course, the borrowing base is next scheduled for review on or before April 27, 2020 and there can be no assurance that the current borrowing base level will be maintained. See *Risk Factors – Credit Facility Arrangements*.

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that there is no borrowing base shortfall, default or event of default under the Credit Facility and no default or event of default could reasonably be expected to result from such payment.

Share Capital

We are authorized to issue an unlimited number of Common Shares and an unlimited number of 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 our SEDAR profile at *www.sedar.com*.

Common Shares

Our 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 the Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by the 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 Shares 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 its 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 TORC or its 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.

Preferred Shares

The Preferred Shares are issuable in series and the designation of, and the rights or privileges, restrictions and conditions attached to any series of Preferred Shares are to be established by our Board of Directors prior to the issuance thereof. The Preferred Shares have a preference over the Common Shares and any of our classes of shares ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of our assets in the event of liquidation, dissolution or winding-up of us or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. No series of Preferred Shares has been designated to date and there are no Preferred Shares outstanding.

DIVIDEND POLICY

Dividends and Dividend Policy

When declared, cash dividends are made 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 day of each such calendar month or such other date as determined from time to time by us.

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

	Dividends per Common Share ($)		
Month	**2019**	**2018**	**2017**
January	0.022	0.020	0.020
February	0.022	0.020	0.020
March	0.022	0.020	0.020
April	0.022	0.020	0.020
May	0.025	0.022	0.020
June	0.025	0.022	0.020
July	0.025	0.022	0.020
August	0.025	0.022	0.020
September	0.025	0.022	0.020
October	0.025	0.022	0.020
November	0.025	0.022	0.020
December	0.025	0.022	0.020
Total	0.288	0.256	0.240

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. Dividends will normally be pre-approved on a quarterly basis in the context of prevailing and anticipated commodity prices and reconfirmed when declared. During periods of volatile commodity prices, we may vary the dividend rate monthly.

In March of 2020, as a result of weakness in commodity prices and reduced global economic activity following the outbreak of COVID-19, we announced a reduction in our monthly dividend from $0.025 per month to $0.005 per month. See *Development of our Business – History and Development – Recent Developments*.

Our long term objective is to set a dividend policy at prudent levels while also pursuing cost-effective per share growth in reserves, production and funds from operations in western Canada. This in turn, is expected to provide a stronger base of funds from operations leading to consistent and sustainable dividends into the future. Our dividend policy is reviewed monthly and is based on a number of factors including current and future commodity prices, foreign exchange rates, and our commodity hedging program, current operations and available investment opportunities.

Our Credit Facility contains restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, 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. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash 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 ABCA for the declaration and payment of dividends applicable law and other factors beyond our control. See *Risk Factors – Dividends*.

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

MARKET FOR OUR SECURITIES

Our Common Shares are listed for trading on the Toronto Stock Exchange under the trading symbol "TOG". The following table sets forth the price range and trading volume of our Common Shares on the Toronto Stock Exchange for the periods indicated.

Period	Price Range ($)		Trading Volume
	Low	High	
2019			
January	4.18	4.95	19,761,703
February	4.09	4.97	20,079,222
March	4.11	4.79	14,187,544
April	4.39	5.46	18,172,734
May	4.06	4.96	15,166,924
June	3.81	4.49	11,965,812
July	3.67	4.41	14,793,467
August	3.03	4.02	19,185,818
September	3.16	4.22	21,639,387
October	3.28	3.94	13,226,265
November	3.38	3.97	14,951,435
December	3.55	4.64	16,262,671
2020			
January	3.78	4.78	16,424,139
February	2.98	4.25	15,219,628
March (to March 20)	0.41	3.45	48,007,788

During the twelve month period commencing on January 1, 2019 and ending on December 31, 2019, we granted an aggregate of 2,832,546 share awards under our share award incentive plan to our officers, directors, employees and certain consultants which may be settled in Common Shares and/or cash, at our option.

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with us of each of our directors and officers as of the date hereof are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
David Johnson (2) Calgary, Alberta	Chairman and Director	Mr. Johnson is an independent businessman with over forty years of diverse experience in the oil & gas industry. Mr. Johnson was the Chairman of Progress Energy Resources Corp. from July 2004 until its sale to PETRONAS in 2012.
John Brussa (3)(4) Calgary, Alberta	Director	Mr. Brussa is Chairman, and has been a partner since 1987, at the law firm of Burnet, Duckworth & Palmer LLP.
Mary-Jo Case (1)(3) Calgary, Alberta	Director	Prior to her retirement in 2015, during the period 2002 to 2015 Ms. Case was a member of the Senior Management Committee at Canadian Natural Resources Limited where she held the positions of Senior Vice President of Land and Human Resources, and Vice President, Land. Ms. Case was responsible for the Canadian merger and acquisition activity overseeing hundreds of acquisitions and dispositions as well as several corporate transactions. During her tenure at CNRL, Ms. Case was also responsible for the management of corporate compensation, recruiting, attrition and people strategy.
M. Bruce Chernoff (2) Calgary, Alberta	Director	Mr. Chernoff has been the President and a Director of Caribou Capital Corp. (a private investment management company) since June 1999 and is the Executive Chairman of PetroShale Inc. Mr. Chernoff was the Chairman of Harvest Energy Trust from 2002 until its sale to the Korean National Oil Corporation in December 2009. Mr. Chernoff has been a Director of Maxim Power Corp. since January 2005 and serves as its Chair of the Board.

Name and Residence	Position	Principal Occupation During Previous Five Years
Catharine de Lacy [4] Charlotte, North Carolina USA		Ms. de Lacy is an independent businessperson and strategic advisor with more than 30 years of prior executive experience globally across a variety of industrial sectors: oil and gas; mining and refining; chemicals and specialty materials; manufacturing; and private label and branded consumer products. She has previously been elected as a Corporate Officer of three Fortune 500 corporations; and has served on executive management and Global Business Unit leadership teams in the energy, chemicals, metals, and aerospace sectors. Her depth of experience and leadership capabilities spans such areas as: Government and Public Affairs; Corporate Communications and Investor Relations; Sustainability and Corporate Social Responsibility; Corporate Governance; Corporate Philanthropy; Environment Health and Safety ("EHS"); Product Stewardship; and Corporate Quality. She has served as a Board member at multiple national and international trade associations; is a recognized thought leader and frequently sought after speaker on such topics as: Environment, Social Responsibility and Governance, Corporate Sustainability, and Corporate EHS Program Leadership; and is a Six Sigma Black Belt. Ms. de Lacy is a member of the Environmental Law Institute's Leadership Council, a strategic advisor to the National Association of Environmental and Sustainability Managers, and is a member of the Executive Advisory Council of the Responsible Battery Coalition. Ms. de Lacy is a graduate of Merrimack College and Tufts University.
John Gordon [1][4] Calgary, Alberta	Director	Mr. Gordon served as the Canadian Managing Partner, Quality and Risk Management, the Canadian Managing Partner, Audit and the Calgary Office Managing Partner for KPMG LLP prior to his retirement in 2018. Mr. Gordon has extensive experience in providing audit and other services to public oil and gas companies. Mr. Gordon is a Chartered Professional Accountant (FCPA), a Chartered Financial Analyst (CFA), and is a graduate of the University of Saskatchewan. Mr. Gordon serves on the Board of the CAMH Foundation, the Alberta Adolescent Recovery Centre, and is a lecturer for, and an active member of the Institute of Corporate Directors.
Brett Herman Calgary, Alberta	Director, President and Chief Executive Officer	Mr. Herman is our President & Chief Executive Officer and a Director. Mr. Herman was the President & Chief Executive Officer and a Director of Result Energy Inc. from November 2009 to April 2010 and the President & Chief Executive Officer and a Director of TriStar Oil & Gas Ltd. from August 2006 to October 2009.

Name and Residence	Position	Principal Occupation During Previous Five Years
R. Scott Lawrence (1)(3) Toronto, Ontario	Director	Mr. Lawrence is the Managing Director, Head of Infrastructure at CPPIB and is an experienced private and public markets investor. Prior to June 2018, Mr. Lawrence was Managing Director, Head of Fundamental Equities. Prior to November 2016, Mr. Lawrence was Managing Director, Head of Relationship Investments at CPPIB, and Senior Principal, Private Investments and Infrastructure at CPPIB from September 2005 to February 2009. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation and a finance professional at GE Plastics and GE Capital Real Estate.
Dale Shwed (2) Calgary, Alberta	Director	Mr. Shwed has been the President & Chief Executive Officer and a Director of Crew Energy Inc. since June 2003.
Jason Zabinsky Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Mr. Zabinsky is our Vice President, Finance and Chief Financial Officer. Mr. Zabinsky was the Vice President and Chief Financial Officer of Result Energy Inc. from November 2009 to April 2010 and the Vice President and Chief Financial Officer of TriStar Oil & Gas Ltd. from January 2006 to October 2009.
Sandy Brown Calgary, Alberta	Vice President, Geosciences	Mr. Brown is our Vice President, Geosciences. Mr. Brown was the New Ventures Manager/Senior Geological Advisor at Apache Canada from November 2007 to November 2014 and the Vice President, Exploration of Rock Energy Inc. from January 2003 to October 2007.
Shane Manchester Calgary, Alberta	Vice President, Operations	Mr. Manchester is our Vice President, Operations. Mr. Manchester was the Vice President, Operations of Vero Energy Inc. from March 2006 to November 2013.
Jeremy Wallis Calgary, Alberta	Vice President, Business Development	Mr. Wallis is our Vice President, Business Development. Mr. Wallis was our Vice President, Land from December 2010 to June 2019 and the Vice President, Land of Result Energy Inc. from November 2009 to April 2010 and the Vice President, Land of TriStar Oil & Gas Ltd. from January 2006 to October 2009.
Mike Wihak Calgary, Alberta	Vice President, Production	Mr. Wihak is our Vice President, Production. Mr. Wihak was the Vice President, Operations of Result Energy Inc. from November 2009 to April 2010 and the Vice President, Operations of TriStar Oil & Gas Ltd. from January 2008 to October 2009.

Name and Residence	Position	Principal Occupation During Previous Five Years
Marvin Tang Calgary, Alberta	Vice President & Controller	Mr. Tang is our Vice President & Controller. Mr. Tang was our Controller from March 2016 to February 2019 and our Assistant Controller from April 2013 to March 2016. Mr. Tang was the Manager of Financial Reporting of Result Energy Inc. from November 2009 to April 2010 and the Manager of Financial Reporting of TriStar Oil & Gas Ltd. from May 2008 to October 2009.

Notes:

(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Environmental, Health, Safety & Sustainability Committee.

Each of our directors were appointed in 2012, other than Mr. Lawrence who was appointed in 2013, Ms. Case who was appointed on January 23, 2018, Mr. Gordon who was appointed on November 5, 2018 and Ms. de Lacy who was appointed on December 11, 2019. All of our directors will hold office until the next annual meeting of our Shareholders or until his or her successor is duly elected or appointed, unless his or her office is earlier vacated in accordance with our articles or by-laws.

Pursuant to an agreement we have with CPPIB, for so long as CPPIB owns greater than 10% of our outstanding Common Shares, it has the right to participate in future offerings of securities by us, whether by way of public offering or private placement. This includes any offering of Common Shares and securities convertible or exchangeable into Common Shares, up to its *pro rata* ownership interest immediately prior to such offering in the case of a public offering or a private placement to five or more investors, in order to maintain its *pro rata* percentage ownership interest in us, and up to all of the offering in the case of a private placement to less than five investors. CPPIB is also entitled to two Board nominees as long as it owns 20% or greater of our outstanding Common Shares. CPPIB currently holds approximately 29.31% of our outstanding Common Shares and has nominated R. Scott Lawrence and Catharine de Lacy as its nominees to our Board.

As a group, our directors and executive officers beneficially own, control or direct, directly or indirectly, 8.65 million Common Shares, representing approximately 3.89% of our outstanding Common Shares. In addition, Mr. Lawrence is the Managing Director, Head of Infrastructure of CPPIB, which holds 65,131,010 Common Shares representing approximately 29.31% of our outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

Except in connection with the other matters disclosed below, 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 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 thirty consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or was subject to such 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 set out 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 materially affect the control of us, 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.

Messrs. Brussa and Chernoff were formerly directors of Calmena Energy Services Inc. ("**Calmena**") (a public oilfield service company). On January 19, 2015, a senior lender of Calmena (the "**Senior Lender**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the *Bankruptcy and Insolvency Act* (Canada) (the "**BIA**") and trading in the common shares of Calmena was suspended by the Toronto Stock Exchange. On January 20, 2015, the Senior Lender was granted a receivership order by the Court. Mr. Brussa resigned as a director of Calmena on June 30, 2014 and Mr. Chernoff resigned effective January 15, 2015.

Mr. Brussa was a director 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 BIA. Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver. 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.

Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**"), a public oil and gas company, on September 1, 2016. On the same day, the senior lenders (the "**Senior Lenders**") of Twin Butte made an application to the Court to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the BIA 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, except as otherwise disclosed herein, 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 materially affect the control of us, has been subject to 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 any other penalties or sanctions imposed by a court or regulatory body.

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

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See *Risk Factors*.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such Board members will be provided to us.

The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his or her interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

The members of our Audit Committee are John Gordon (Chair), Mary-Jo Case and R. Scott Lawrence.

The Audit Committee operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Schedule "A".

The Audit Committee charter requires all members of the Audit Committee to be financially literate and independent within the meaning of applicable securities laws. All current members of the Audit Committee meet these requirements.

The Audit Committee charter requires that any non-audit services by our auditors must be pre-approved by the Audit Committee.

Education and Experience of Members

The education and experience of each director relevant to the performance of his or her duties as a member of the Audit Committee are described below.

John Gordon (Chair)

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

Mary-Jo Case

Ms. Case holds a Diploma in Legal Office Administration from Fanshawe College. During her tenure, from 2002 to 2015, as a Senior Executive at Canadian Natural Resources Limited Ms. Case was a member of the Senior Management Committee gaining experience in finance, audit procedures and practices. Prior thereto Ms. Case obtained exposure in finance and audit through ever increasing management roles at PanCanadian Energy/PanCanadian Petroleum.

R. Scott Lawrence

Mr. Lawrence holds a MBA degree from Harvard Business School and a B.Comm (Hons) degree from Queen's University. Mr. Lawrence is a holder of the Institute of Corporate Directors, Director designation and has extensive board experience, including positions on the boards of Entertainment One Ltd., Progress Energy Resources Corp., and Transelec S.A. Mr. Lawrence is the Managing Director, Head of Infrastructure at CPPIB and is an experienced private and public markets investor. Prior to June 2018, Mr. Lawrence was Managing Director, Head of Fundamental Equities. Prior to November 2016, Mr. Lawrence was Managing Director, Head of Relationship Investments at CPPIB, and Senior Principal, Private Investments and Infrastructure at CPPIB from September 2005 to February 2009. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation and a finance professional at GE Plastics and GE Capital Real Estate

Auditor's Fees

KPMG LLP is our auditor. The following table sets out the aggregate fees billed by KPMG LLP to us in each of the last two fiscal years.

Year	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees
2019	$330,000	$Nil	$Nil	$Nil
2018	$307,000	$Nil	$Nil	$Nil

Notes:

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

(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. The services provided in this category included research of accounting and audit-related issues, review of internal controls and language translation.

(3) Fees for tax compliance, tax advice and tax planning.

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, Saskatchewan and Manitoba. 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 the provinces in which we operate.

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 dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

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 tonnes 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/d 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 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 are not and have not been subject to 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.

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.

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.

Manitoba

In Manitoba, the Crown owns only approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to approximately 42.8% based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

The Government of Manitoba maintains a Drilling Incentive Program (the "**MB Incentive Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The MB Incentive Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no royalties are payable until the holiday oil volume has been produced. The MB Incentive Program consists of benefits that are specific to certain vertical, exploration, and deep wells, as well as wells undergoing major workovers, wells for solution gas, and wells converted to injection wells. The MB Incentive Program was extended without alteration in April, 2019 to December 31, 2020.

Producers of crude oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and approximately 40% based on the monthly production volume and the classification of crude oil as old oil, new oil, third-tier oil, and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

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 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 GHG 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.

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.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Crude oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the "**MBOGA**"), *The Oil and Gas Production Tax Act* and related regulations and guidelines.

Pursuant to the MBOGA, the Government of Manitoba recently launched an online database for the publication of missing royalty owner applications, to help alleviate uncertainty for royalty owners and payors. A person may make an application on behalf of a royalty owner, when the identity or whereabouts of a royalty owner in a tract or spacing unit cannot be ascertained, for an order authorizing the exploration for oil and natural gas.

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 an inactive liability reduction target to be met through closure work of inactive assets. We are not a participant in the voluntary ABC program.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund 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.

Manitoba

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

Climate Change Regulation

Climate change regulation at 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 our operations and funds flow.

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 CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (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 CO2e 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.

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 CO2 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 CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e 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.

Manitoba

On March 15, 2018, Manitoba unveiled the *Climate and Green Plan Implementation Act*. The Act includes five separate acts that cover a variety of environmental and economic areas including climate change, greenhouse gas emissions, water protection, income tax and fuel tax related measures. The Climate and Green Plan removes the previous $25/tonne provincial tax on carbon. On June 11, 2019, the Government of Manitoba set its GHG emission reduction target at one megatonne for the 2018-2022 period. The announcement makes Manitoba the first jurisdiction in North America to establish a set emissions reductions goal in rolling five-year periods.

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

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends on, and the market price of, our Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. Cash dividends to Shareholders are not assured or guaranteed.

Before deciding whether to invest in any Common Shares, investors should consider carefully the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations.

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled *Special Note Regarding Forward-Looking Statements*.

COVID-19

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, have 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 and reduced 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.

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, Organization of the Petroleum Exporting Countries ("**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 the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

See *Industry Conditions – Transportation Constraints and Marketing* and *Weakness and Volatility in the Oil and Natural Gas Industry* in these Risk Factors.

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

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, and pipeline systems. 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. Notwithstanding the Government of Alberta's plans to purchase 7,000 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in our inability to realize the full economic potential of our production, or in a reduction of the price offered for our production. The lack of firm pipeline capacity 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*. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to 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 could also affect our production, operations and financial results. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, operations and funds from operations. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing for receipt of approvals of major projects remains 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.

Weakness in the Oil and Gas Industry

Market events and conditions, including COVID 19, global excess oil and natural gas supply, recent actions taken by OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, 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 flows from operating activities resulting in less cash flows from operating activities being available to fund our capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year-over-year basis. See *Reserves Estimates* in these Risk Factors. Any decrease in value of our reserves may reduce the borrowing base under the Credit Facility, which, depending on the level of our indebtedness, could result in us having to repay a portion of our indebtedness. See *Credit Facility Arrangements* in these Risk Factors. In addition to possibly resulting in a decrease in the value of our economically recoverable reserves, lower commodity prices may also result in a decrease in the value of our infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of our oil and natural gas assets on our balance sheet and the recognition of an impairment charge on our income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. See *Additional Funding Requirements* in these Risk Factors.

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 securities.

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 the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Changing Investor Sentiment

A number of factors, including 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 production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, 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 asset which may result in an impairment change.

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 funds from operations 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.

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:

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

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

Market Price

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of 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 securities 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 securities will trade cannot be accurately predicted.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur, from time to time, in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See *Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*. Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See *Industry Conditions – Curtailment*. Also see *Liability Management* in these Risk Factors.

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

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.

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 securities.

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.

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

Credit Facility Arrangements

The amount authorized under the Credit Facility is dependent on the borrowing base determined by our lenders. 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 Common Shares, 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.

There is no assurance that the maturity of the Credit Facility will be extended upon our request in the amounts requested or upon terms acceptable to us.

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 impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See *Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under the Credit Facility, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. We may also be required to provide additional reporting to our lenders regarding our existing and/or budgeted abandonment and reclamation obligations, our decommissioning expenses, our LMR and/or any notices or orders received from an energy regulator in any applicable province. 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 the 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 under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

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, as well as the cost of, additional financing.

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

Hedging

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

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

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

Reserves Estimates

There are numerous uncertainties inherent in estimating reserves, and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net 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 revenue to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

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.

Dividends

The amount of future cash dividends we pay, if any, will be subject to the discretion of our 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 control, our dividend policy may vary 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 funds from operations, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operations.

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

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. Losing the services of such key personnel could have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key personnel insurance in effect. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the 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. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

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 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 – Liability Management Rating Program* and *Third Party Credit Risk* in these Risk Factors.

Royalty Regimes

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

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business, as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Reservoir Pressure Maintenance

We undertake or intend to undertake certain pressure maintenance programs, which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such pressure maintenance activities we need to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that we will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as pressure maintenance. If we are unable to access such water it may not be able to undertake pressure maintenance activities, which may reduce the amount of oil and natural gas that we are ultimately able to produce from our reservoirs. In addition, we may undertake certain pressure maintenance programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on our results of operations.

Environmental

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system 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*. Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of our deemed assets to deemed liabilities, or other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. In addition, the liability management regime 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.

The impact and consequences of the Supreme Court of Canada decision in the Redwater case 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 will no doubt evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. See *Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*.

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.

Issuance of Debt

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

Title to and Right to Produce from Assets

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

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

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.

Income Taxes

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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.

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.

Litigation

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

Insurance

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

Breach of Confidentiality

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

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

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 ABCA 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 ABCA. See *Directors and Officers – Conflicts of Interest*.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Climate Change

Our Chronic Climate Change Risks

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a 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* 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.

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 and 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 if subjected to 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.

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.

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.

Non-Governmental Organizations

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

Indigenous Claims

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

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.

We Require a Skilled Workforce

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. We compete with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Social Media

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. We restrict the social media access of our employees and periodically review, supervise, retain and maintain the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that 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.

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 *Special Note Regarding Forward-Looking Statements* of this Annual Information Form.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2019, nor are there any such proceedings known to us to be contemplated.

During the year ended December 31, 2019 there were (i) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as may be disclosed elsewhere in this Annual Information Form, none of our directors, officers or principal shareholders, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect us or any of our affiliates.

AUDITOR, TRANSFER AGENT AND REGISTRAR

Our auditor is KMPG LLP, Chartered Professional Accountants. KPMG LLP has been our auditor since January 24, 2011.

Our transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within our most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, is our credit agreement in respect of our Credit Facility and our agreement with CPPIB, which are available on our SEDAR profile at *www.sedar.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator, and KPMG LLP, our independent auditor.

We used KPMG LLP for external audit services for the fiscal year ended December 31, 2019. KPMG LLP are our auditors and 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.

Reserve estimates by Sproule are included in this Annual Information Form. None of the designated professionals of Sproule 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 statement, report or valuation prepared by it, at any time thereafter or to be received by them.

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 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.torcoil.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans will be contained in our information circular and proxy statement for our annual and special meeting of shareholders to be held on May 6, 2020. Additional financial information is contained in our financial statements and the related management's discussion and analysis for the year ended December 31, 2019.

SCHEDULE "A"

AUDIT COMMITTEE CHARTER
TORC OIL & GAS LTD.

Role of the Audit Committee

The Audit Committee is a committee of the Board of Directors ("**Board**") of TORC Oil & Gas Ltd. (the "**Corporation**") to which the Board has delegated its fiduciary responsibility for oversight of the material financial risks of the Corporation. Financial risks include risk of: material misstatement in the financial statements or disclosures; and non-compliance with related regulations.

The Audit Committee ("**Committee**") carries out its responsibilities in cooperation with management, external auditors and external advisors on behalf of the Board. Following each meeting of the Committee, the Chairman of the Committee will make a report to the Board.

Composition of the Committee

The Chairman and members of the Committee are appointed by the Board and are required to be financially literate and independent of the Corporation.

The Audit Committee shall consist of at least three independent directors.

A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – *Audit Committees* or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

Chairman

The Board shall appoint the chairman of the Committee (the "**Chairman**"). The role of the Chairman is to act as leader of the Committee to manage and co-ordinate the meetings and activities of the Committee and to oversee the execution by the Committee of its duties and responsibilities.

If the Chairman of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of members of the Committee present at such meeting.

Authority of the Committee

The Committee shall have complete access to our personnel and the books and records of the Corporation. The Committee has the authority to engage external advisors if necessary to discharge its responsibilities and has the authority to fix compensation and authorize payment.

Audit Committee Meetings

The Committee carries out its duties through scheduled regular scheduled meetings or special meetings that may be requested by the Board, officers of the Corporation or the external auditor. The schedule, time and location of regular Audit Committee meetings is determined by the Chairman of the Committee and they generally coincide with the timing of the quarterly financial statements, management discussion and analysis, and financial press release.

Notice and Conduct of Meetings

Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

Notice of a meeting of the Audit Committee shall:

- be in writing;
- state the nature of the business to be transacted at the meeting in reasonable detail;
- to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and
- be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.

Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Responsibilities of the Audit Committee

Committee Member Responsibilities

Knowledge of the business, financial and regulatory requirements

Committee members shall have and maintain a sufficient knowledge of company operations and changes in operations including the principal risks, systems and abilities of key personnel involved in financial reporting and disclosure processes to reasonably discharge their duties.

Independence

Audit Committee members have an obligation to remain independent of the affairs of the Corporation and shall disclose any circumstances that create a conflict of interest with role of a Committee member or may appear to create a conflict of interest.

Committee Responsibilities

The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

Management Oversight

It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that management has:

- identified the principal financial, regulatory and fraud risks; and,
- designed and implemented an adequate system of internal controls to mitigate the risks.

Review of the Corporation's Financial Statements & Disclosures

It is the responsibility of the Audit Committee to critically review the financial statements and disclosures of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should also include but not be limited to review of:

- Changes in Accounting Policies
- Significant Management estimates
- Material or unusual transactions
- Material agreements

Review and Approve Significant Matters

It is the responsibility of the Audit Committee to review significant policies and matters that may materially impact financial statements and disclosures including but not limited to the following:

Accounting policies

The Audit Committee shall review the appropriateness of the accounting policies of the Corporation and approve significant policies.

Risk management

The Audit Committee shall review the risk management policies and procedures of the Corporation (i.e. hedging, litigation, insurance and marketing counterparty credit risk), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.

Limits of authority

The Audit Committee shall periodically review the manner of delegation and limits of authority that management has implemented throughout the Corporation.

Litigation

The Audit Committee shall review the status of outstanding litigation at each regular Committee meeting.

Accounting Principle Changes

The Audit Committee shall schedule periodic updates on changes in accounting principles, regulations and emerging issues that may be relevant to the Corporation.

External Audit Responsibilities

It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

Appointment of external auditors

The Audit Committee shall:

- recommend to the Board the appointment of the external auditors;
- review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;
- oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;
- recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee; and,
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

Annual audit plan review

Audit Committee shall review the annual audit plan with the external auditors; monitor progress; and, upon completion of the audit, review their reports on the financial statements of the Corporation and its subsidiaries. The review should consider scope, approach, audit team experience and fees.

Non-audit services

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

Meet separately from management

The Audit Committee shall meet with the external auditors apart from management at each regular meeting to receive assessments relating to audit scope limitations, management cooperation and any issues relating to financial competencies.

Recommendations to Board

The Audit Committee is responsible for reviewing financial statements, disclosures and other significant policies and providing recommendations to the Board. Standing recommendations include:

- Appointment of external auditors
- Approval of financial statements, MD&A and other disclosure documents.
- Significant policies

Complaint System (Whistleblower Policy)

The Audit Committee shall establish and maintain procedures for:

- the receipt, retention and treatment of complaints received by the Corporation regarding ethical matters and business practices; and
- the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable ethical matters and business practices.

SCHEDULE "B"

FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of TORC Oil & Gas 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 audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2019	Canada	Nil	2,115,975	Nil	2,115,975

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 report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report entitled, "Evaluation of the P&NG Reserves of TORC Oil & Gas Ltd. (As of December 31, 2019)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 27, 2020

Original signed by Paul B. Jung, P.Eng.
Paul B. Jung, P.Eng.
Senior Petroleum Engineer

Original signed by Robert R. Warholm, P.Eng.
Robert R. Warholm, P. Eng.
Senior Manager, Quality & Assurance

Original signed by Irina Baiseitova, P.Eng.
Irina Baiseitova, P.Eng.
Senior Petroleum Engineer

Original signed by Gary R. Finnis, P.Eng.
on behalf of Weldon D. Dueck, P.Eng.
Weldon D. Dueck, P.Eng.
Senior Petroleum Engineer

Original signed by Rodney E. Fradette, P.Eng.
Rodney E. Fradette, P.Eng.
Senior Petroleum Engineer

Original signed by Tanja M. Hale, P.Eng.
Tanja M. Hale, P.Eng.
Senior Petroleum Engineer

Original signed by Shishir Shivhare, P.Eng.
Shishir Shivhare, P.Eng.
Petroleum Engineer

Original signed by Cameron P. Six, P.Eng.
Cameron P. Six, P.Eng.
President and CEO

Original signed by Ian K. Kirkland, P.Geol.
Ian K. Kirkland, P.Geol.
Senior Geologist

SCHEDULE "C"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of TORC Oil & Gas Inc. ("**TORC**") is responsible for the preparation and disclosure of information with respect to TORC's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated and reviewed TORC's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "B" to the Annual Information Form of TORC for the year ended December 31, 2019 (the "**AIF**").

The reserves committee (the "**Reserves Committee**") of the board of directors of TORC (the "**Board of Directors**") has:

(a) reviewed TORC's procedures for providing information to the independent qualified reserves evaluator, Sproule Associates Limited ("**Sproule**");

(b) met with Sproule to determine whether any restrictions affected the ability of Sproule to report without reservation; and

(c) reviewed the reserves data with management and with Sproule.

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

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

(d) the filing of Form 51-101F2, which is the report of Sproule on the reserves data, contingent resources data or prospective resources data; and

(e) the content and filing of this report.

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

(signed) "*Brett Herman*"	(signed) "*Mike Wihak*"
Brett Herman President & Chief Executive Officer	Mike Wihak Vice-President, Production
(signed) "*Dale Shwed*"	(signed) "*David Johnson*"
Dale Shwed Director & Chairman of the Reserves Committee	David Johnson Director and Chairman of the Board

February 27, 2020