CLEARVIEW RESOURCES LTD

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

April 29, 2020

TABLE OF CONTENTS

CONVENTIONS

Unless otherwise indicated, any reference in this Annual Information Form to "**Clearview**", "**us**", "**we**", "**our**" or the "**Company**" means Clearview Resources Ltd. Certain other terms used but not defined herein are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) (the "**COGE Handbook**"), the Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*, and under the heading "*Selected Abbreviations*" herein. Unless otherwise specified, information in this Annual Information Form is as at the end of our most recently completed financial year, being December 31, 2019. All dollar amounts herein are Canadian dollars, unless otherwise stated. See "*Selected Abbreviations*," "*Selected Conversations*," "*Forward-Looking Statements*" and "*Certain Reserve Data* Information". Corporate documents, such as Management Discussion and Analyses, and interim financial filings, can be found online at **www.sedar.com**.

CORPORATE STRUCTURE

Name, Address, and Incorporation

We were initially incorporated on February 19, 1980 under the *Companies Act* (British Columbia) ("**Companies Act**"), under the name "Panorama Petroleums Ltd." Following incorporation, we filed Articles of Amendment to effect the following changes: (i) on September 28, 1987, we changed our name from "Panorama Petroleums Ltd." to "Panorama Resources Ltd."; (ii) on April 14, 1993, we changed our name from "Panorama Resources Ltd." to "International Panorama Resource Corp."; (iii) on September 30, 2002, we changed our name from "International Panorama Resource Corp." to "Kakanda Development Corp."; (iv) on January 19, 2007, we changed our name from "Kakanda Development Corp." to "KDC Energy Ltd."; (v) on February 14, 2007, we continued from the Province of British Columbia to the Province of Alberta, under the *Business Corporations Act* (Alberta) (the "**ABCA**"); and (vi) on June 6, 2011, we changed our name from "KDC Energy Ltd." to "Clearview Resources Ltd."

On August 1, 2018 we amalgamated with our then wholly owned subsidiary Bashaw Oil Corp. ("**Bashaw**") to form the current Clearview Resources Ltd. As of the date of this annual information form (the "**AIF**") we do not have any subsidiaries.

Our head office is located at 2400, 635 – 8th Ave S.W., Calgary, AB T2P 3M3, and our registered office is located at 15th floor, Bankers Court, 850 – 2nd Street S.W., Calgary, AB T2P 0R8.

DESCRIPTION OF THE BUSINESS

Overview

We are a junior oil and natural gas producing company based in Calgary, Alberta. We are focused on long-term growth, implemented through a disciplined acquisition, development and production optimization program in Canada. Our business strategy is to maximize shareholder value by increasing reserves, production and cash flows through the development of a continually growing asset base.

For further information, readers can view our public disclosures available on the Canadian Securities Administrator's System for Electronic Distribution and Retrieval ("**SEDAR**") at www.sedar.com, and on our website at www.clearviewres.com.

Business Strategy

Clearview has transformed from a non-operated producer into a growth-oriented, light oil focused operator of a majority of our production. Building on the properties acquired in the Greater Pembina area late in fiscal 2017 with the acquisition of Bashaw and the disposition of certain non-core assets, we have moved forward with a successfully operated, light oil focused drilling program at Wilson Creek and Windfall in Alberta.

These transactions and our capital program are significant milestones towards our objectives, which continue to be:

- acquire long life, cash generating oil and natural gas properties with growth potential;
- maintain a low cost and financially robust structure;
- maintain an appropriate debt versus equity capital structure;
- build our production base to fund the field capital program from internally generated funds;
- maintain strong lending values to support our credit facility;
- maintain a licensee liability rating of 2.0 or greater, securing the ability to transact on further acquisition opportunities; and
- evaluate non-core assets, for potential disposition, to maximize efficiencies and fund the capital program.

General Development of the Business

Year Ended March 31, 2017

During the fiscal year ended March 31, 2017, we completed two strategic acquisitions of oil and liquid rich natural gas properties, both in West Central Alberta, and both with significant, low-risk development potential and operatorship of most of the lands and wells. In February 2017, we acquired properties in Wilson Creek for $11.4 million. In March 2017, we acquired properties in Northville, Pembina and Caribou for $20.1 million. We arranged revised loan facility agreements with a leading provincial lender with each of the acquisitions, resulting in a facility limit of $26.0 million at March 31, 2017.

In addition to these acquisitions, we also closed three tranches of equity financing by issuing our common shares (the "**Common Shares**"), as follows: (i) 1,111,111 Common Shares were issued on August 4, 2016, for $4.50 per share, or aggregate proceeds of $5.0 million; (ii) 1,040,051 Common Shares were issued on February 15, 2017 for a purchase price of $5.00 per Common Share, or aggregate proceeds of $5.2 million; and (iii) 3,187,922 Common Shares were issued on March 30, 2017 for a purchase price of $5.00 per Common Share, or aggregate proceeds of $15.9 million.

Year Ended March 31, 2018

During the fiscal year ended March 31, 2018, we focused on integrating the properties we acquired in the prior year and undertook several recompletion operations on the new properties.

On January 4, 2018, we acquired a 50% working interest in producing light oil and natural gas assets in the Windfall area of West Central Alberta. The purchase price we paid was $3.4 million for 55 bbls/d of light oil and liquids and 330 mcf/d of sweet natural gas.

Transition Year – Nine Months Ended December 31, 2018

On April 10, 2018, we closed the disposition of a non-core, non-operated light oil property located in southern Alberta for $3.4 million.

On April 16, 2018, we closed the acquisition of Bashaw by way of an amalgamation of Bashaw with a newly incorporated subsidiary of Clearview. The transaction took place through a share for share exchange based on 25.379 common shares of Bashaw for one of our Common Shares. We issued 1,560,046 Common Shares to the shareholders of Bashaw pursuant to this acquisition.

In connection with the acquisition of Bashaw, the composition of our management was changed. Mr. Tony Angelidis was appointed as our new President and Chief Executive Officer, Mr. Brian Kohlhammer was appointed as our Vice President Finance and Chief Financial Officer and Mr. Darcy Ries was appointed as our Vice President Engineering and Chief Operating Officer. Additionally, Mr. Timothy Halpen was appointed to our board of directors. See "*Directors and Officers*" in this AIF.

On November 21, 2018 we filed a notice of change of year end pursuant to section 4.8(2) of National Instrument 51-102 – *Continuous Disclosure Obligations* ("**NI 51-101**") changing our fiscal year end from March 31 to December 31.

During the transition year, our lender reconfirmed our credit facility at $21.0 million, with the next scheduled review set for no later than June 30, 2019.

We closed a private placement in November 2018, issuing 210,390 Common Shares at a price of $6.25 per share for gross proceeds of $1.3 million and 101,543 flow-through Common Shares at a price of $7.00 per share for gross proceeds of $0.7 million. Total gross proceeds raised from the private placement was $2.0 million.

Year Ended December 31, 2019

On February 22, 2019, we acquired certain oil and gas assets from C Group Energy Inc. for total consideration of $9.5 million. The purchase price consisted of $0.58 million in cash and the issuance of 1.362 million Common Shares at a deemed price of $6.516. Consequently, C Group Energy Inc. is now one of our majority shareholders, holding 1,361,542 Common Shares, amounting to approximately 11.67% of the issued and outstanding Common Shares.

In October of 2019, following a review of the existing credit facility, our lender confirmed our credit facility at a limit of $18.5 million, with the next scheduled review being no later than June 30, 2020.

Potential acquisitions and Financings

We continue to evaluate potential acquisitions of petroleum and natural gas and other energy-related assets and/or companies as part of our ongoing acquisition program. We are regularly in the process of evaluating several potential acquisitions at any one time, which individually or together could be material. We cannot predict whether any current or future opportunities will result in one or more acquisitions for us. In addition, we may, in the future, complete financings of equity or debt (which may be convertible into equity) for purposes that may include financing of acquisitions, our operations and capital expenditures and repayment of indebtedness.

Core Areas of the Business

The following is a description of our five core areas:

Wilson Creek

Wilson Creek is located 100 kilometres west of Edmonton, Alberta. We hold an average working interest of approximately 64 percent and are the operator of our production and working interest lands. The primary reservoirs are the Cardium oil resource play and liquids rich natural gas from deeper Cretaceous and Triassic formations. The key characteristic of the light oil resource play is 32° - 37° API oil, predictable geology and production profiles as well as consistent and repeatable economics. Liquids rich natural gas is produced from the Manville group of formations. In August of 2018, we drilled, completed and equipped Wilson Creek 15-20-44-4W5; a Cardium horizontal well and a first for us as operator.

Windfall

Our Windfall property was acquired on January 4, 2018. We acquired a 50% working interest in the property for cash consideration of $3.4 million. The property is located 175 kilometres northwest of Edmonton, Alberta. The Windfall property is characterized as a light oil Bluesky channel of 36° - 40° API oil with associated natural gas production. During the year ended December 31, 2018, we became operator of the Windfall property with a 100% working interest through the acquisition of the operator, Bashaw. Subsequent to the drilling at Wilson Creek, we drilled the 1-3-59-15W5M well at Windfall. The 1-3 well was completed, equipped and placed on production in November 2018.

Northville/Pembina

The Northville and Pembina fields are located 125 kilometres west of Edmonton, Alberta. We operate our production and lands with an average working interest of approximately 89 percent at Northville and 80 percent at Pembina. Both fields are characterized as liquids rich natural gas fields with production primarily coming from the Glauconite and Rock Creek formations. Natural gas production is processed at third party deep cut processing facilities resulting in natural gas liquids production of ethane, propane, butane and pentanes.

Niton

Our Niton property was acquired on February 22, 2019. We acquired a 96% working interest in the property as part of an acquisition of a group of assets from a private company for cash consideration of $0.6 million and 1.36 million common shares of Clearview. The property is located 160 kilometres west of Edmonton, Alberta. The Niton property is primarily focussed on the development of the Cardium formation producing light oil of 30° - 35° API oil with associated natural gas production. Additional oil is produced from the Ellerslie formation.

Garrington

The Garrington assets were also acquired on February 22, 2019 as part of the acquisition of a group of assets from a private company. We acquired an average 94% working interest in the property. The property is located 100 kilometres north of Calgary, Alberta. Light oil production comes from the Cardium and Glauconitic formations, with additional liquids-rich gas production from the underlying Mississippian Elkton formation. The key characteristic of the light oil play is 35° - 40° API oil.

We seek to grow shareholder value by: targeting strategic acquisitions focused on under-developed conventional and unconventional assets; drilling and developing our core assets and undeveloped land position; deploying leading edge innovative technologies in drilling and completions, production and operations; achieving operational excellence via field optimization and cost efficiencies; and maintaining a strong balance sheet and corporate financial flexibility.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below is dated March 18, 2020 and effective as at December 31, 2019. The information contained herein was prepared as of March 18, 2020.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by McDaniel & Associates Consultants Ltd. ("**McDaniel**") with an effective date of December 31, 2019 as contained in the report prepared by McDaniel (the "**McDaniel Report**"). The reserves data summarizes the crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities.

The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of our proved and proved + probable reserves. No attempt was made to evaluate possible reserves.

All of the reserves specified in the McDaniel Report are in Western Canada and, specifically, in the Province of Alberta.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates described herein are estimates only. The actual reserves may be greater or less than those calculated.

The estimates of reserves and future net revenue 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 aggregations.

Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf equals 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.

In certain of the tables set forth below, the columns and rows may not add due to rounding.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS DECEMBER 31, 2019 FORECAST PRICES AND COSTS						
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS [3]	
RESERVES CATEGORY	Gross [1] (Mbbls)	Net [2] (Mbbls)	Gross [1] (MMcf)	Net [2] (MMcf)	Gross [1] (Mbbls)	Net [2] (Mbbls)
Proved						
Developed Producing	1,447.1	1,252.5	15,948.7	14,347.7	983.2	738.3
Developed Non-Producing	202.5	176.1	1,657.2	1,545.2	43.6	33.8
Undeveloped	3,111.5	2,717.6	14,993.9	13,625.3	621.4	512.5
Total Proved	4,761.2	4,146.2	32,599.8	29,518.1	1,648.3	1,284.7
Probable	2,172.4	1,789.3	31,848.1	29,046.8	2,110.8	1,773.1
Total Proved + Probable	6,933.6	5,935.5	64,447.9	58,564.9	3,759.1	3,057.8

Notes:

(1) Gross reserves are working interest reserves before royalty deductions.
(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.
(3) NGLs includes condensate volumes.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) [1]						
RESERVES CATEGORY	0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	Unit Value Before Income Tax Discounted at 10% per Year $/BOE [1]
Proved						
Developed Producing	24,968.8	32,980.4	33,277.5	31,366.2	28,991.1	6.48
Developed Non-Producing	10,326.4	7,824.9	6,125.5	4,925.6	4,049.8	11.51
Undeveloped	97,993.1	69,481.2	48,619.7	34,292.5	24,383.8	7.75
Total Proved	133,288.2	110,286.5	88,022.7	70,584.3	57,424.7	7.37
Probable	135,500.3	89,544.0	60,405.0	42,276.0	30,558.6	6.30
Total Proved + Probable	268,788.5	199,830.5	148,427.7	112,860.3	87,983.3	6.88

Note:

(1) The unit values are based on net reserve volumes.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)
Proved					
Developed Producing	24,968.8	32,980.4	33,277.5	31,366.2	28,991.1
Developed Non-Producing	10,326.4	7,824.9	6,125.5	4,925.6	4,049.8
Undeveloped	93,777.9	66,990.7	47,097.1	33,333.2	23,763.2
Total Proved	129,073.0	107,796.0	86,500.0	69,625.0	56,804.1
Probable	103,638.8	68,474.6	45,717.9	31,618.3	22,580.7
Total Proved + Probable	232,711.8	176,270.6	132,217.9	101,243.3	79,384.7

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

Reserves Category	Revenue (1) ($000's)	Royalties (2) ($000's)	Operating Costs ($000's)	Development Costs ($000's)	Abandonment And Reclamation Costs (3) ($000's)	Future Net Revenue Before Income Taxes ($000's)	Income Taxes ($000's)	Future Net Revenue After Income Taxes ($000's)
Total Proved	540,890	64,812	203,109	99,199	40,482	133,288	4,215	129,073
Total Proved + Probable	923,006	111,201	335,258	160,796	46,963	268,789	36,077	232,712

Notes:

(1) Includes all product revenues and other revenues as forecast.
(2) Royalties include Crown, freehold and overriding royalties and mineral taxes.
(3) For more information, see "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (Discounted at 10%/year) (M$C)	Unit Value(1) ($/Bbl)	($/Mcf)
Proved				
	Light and Medium Crude Oil (2)	69,663	16.91	-
	Conventional Natural Gas (3)	18,359	-	1.21
	Total	**88,023**		
Proved + Probable				
	Light and Medium Crude Oil (2)	108,429	18.39	-
	Conventional Natural Gas (3)	39,999	-	1.08
	Total	**148,428**		

Notes:

(1) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.
(2) Includes solution gas and other associated by-products.
(3) Includes by-products but excluding solution gas.

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" the following definitions and other notes are applicable:

1. "**gross**" means:

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

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

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

2. "**net"** means:

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

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

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

3. Definitions used for reserve categories are as follows:

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

(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.

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

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

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

Development and Production Status

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

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

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

(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.

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

7. "**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 gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

8. "**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.

9. "**forecast prices and costs**"

These are prices and costs that are:

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

(b) based on an average of forecast prices and costs as forecast by three different consultants; and

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

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

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

Pricing Assumptions

The forecast cost and price assumptions in this statement for reserves assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	Oil			Natural Gas		Natural Gas Liquids			
Year	WTI Cushing Oklahoma ($USD/bbl)	Edmonton Light Crude Oil ($CAD/bbl)	Alberta Bow River Hardisty Crude Oil ($CAD/bbl)	U.S. Henry Hub Gas Price ($USD/bbl)	Alberta AECO Spot ($CAD/MMbtu)	Edmonton Propane ($CAD/bbl)	Edmonton Butane ($CAD/bbl)	Inflation Rates (%/year)[1]	Exchange Rate (USD/CAD)[2]
2020	61.00	72.64	58.43	2.62	2.04	26.36	42.10	-	0.76
2021	63.75	76.06	63.00	2.87	2.32	29.80	47.03	1.7	0.77
2022	66.18	78.35	64.99	3.06	2.62	32.94	50.66	2.0	0.785
2023	67.91	80.71	66.91	3.17	2.71	34.00	52.21	2.0	0.785
2024	69.48	82.64	68.65	3.24	2.81	34.88	53.48	2.0	0.785
2025	71.07	84.60	70.41	3.32	2.89	35.78	54.77	2.0	0.785
2026	72.68	86.57	72.20	3.39	2.96	36.69	56.07	2.0	0.785
2027	74.24	88.49	73.91	3.45	3.03	37.57	57.32	2.0	0.785
2028	75.73	90.31	75.53	3.53	3.09	38.41	58.50	2.0	0.785
2029	77.24	92.17	77.18	3.60	3.16	39.26	59.71	2.0	0.785
2030	78.79	94.01	78.72	3.67	3.23	40.04	60.90	2.0	0.785
2031	80.36	95.89	80.29	3.74	3.29	40.85	62.12	2.0	0.785
2032	81.97	97.81	81.90	3.82	3.36	41.66	63.36	2.0	0.785
2033	83.61	99.76	83.54	3.89	3.43	42.50	64.63	2.0	0.785
2034	85.28	101.76	85.21	3.97	3.49	43.35	65.92	2.0	0.785
Thereafter	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	2.0%	0.785

Notes:

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

Weighted average historical prices realized for the twelve months ended December 31, 2019, excluding price risk management activities, were, $64.69/bbl for light and medium crude oil, $1.83/mcf for conventional natural gas and $25.69/bbl for natural gas liquids.

Reserves Reconciliation

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS						
	Total Light and Medium Crude Oil			Total Natural Gas[1]		
	Proved (Mbbl)	Probable (Mbbls)	Proved + Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (MMcf)	Proved + Probable (MMcf)
December 31, 2018	4,329	1,426	5,756	30,628	27,061	57,689
Extensions	109	26	135	351	102	453
Technical Revisions	(116)	43	(73)	(958)	1,086	128
Acquisitions	692	677	1,369	5,328	3,599	8,927
Dispositions	-	-	-	-	-	-
Production	(253)	-	(253)	(2,749)	-	(2,749)
December 31, 2019	4,761	2,172	6,934	32,600	31,848	64,448
	Total Natural Gas Liquids			Total		
	Proved (Mbbl)	Probable (Mbbls)	Proved + Probable (Mbbls)	Gross Proved (Mbbls)	Gross Probable (MMcf)	Proved + Probable (MMcf)
December 31, 2018	1,497	1,703	3,200	10,931	7,639	18,570
Extension	17	5	22	185	48	233
Technical Revisions	(45)	190	145	(322)	415	93
Acquisitions	351	213	564	1,932	1,490	3,422
Dispositions	-	-	-	-	-	-
Production	(171)	-	(171)	(883)	-	(883)
December 31, 2019	1,649	2,111	3,760	11,843	9,592	21,435

Note:

(1) Includes solution gas volumes.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

All of the proved undeveloped reserves are in core areas where we are actively spending capital to develop those properties. For more information, see "*Future Development Costs*". There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

We typically use our internally generated cash flow, proceeds from dispositions, available credit facilities and new equity financings, if available on favourable terms, to fund requirements for future development required to develop the proved or the proved + probable reserves.

Proved Undeveloped Reserves

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

	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2016	-	64	-	100	-	85
2017	839	942	12,218	12,368	804	811
2018	383	1,319	-	5,208	-	258
2018*(1)	464	2,585	1,853	11,821	35	414
2019	109	3,112	182	14,994	12	621

Note:

(1) The "2018*" notation refers to the period between April 1, 2018 and December 31, 2018, and the simple "2018" refers to the period between April 1, 2017 and March 31, 2018.

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. McDaniel has assigned 6.23 MMboe of proved undeveloped reserves in the McDaniel Report with $99.2 million of associated undiscounted capital.

Probable Undeveloped Reserves

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

	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Year	First Attributed	Cumulative at Year End
2016	-	80	-	128	-	5
2017	575	626	11,883	11,962	781	785
2018	245	871	10,581	22,543	559	1,344
2018*(1)	660	867	3,947	21,961	26	1,435
2019	26	1,655	51	26,668	3	1,815

Note:

(1) The "2018*" notation refers to the period between April 1, 2018 and December 31, 2018, and the simple "2018" refers to the period between April 1, 2017 and March 31, 2018.

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 + 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. McDaniel has assigned 9.59 MMboe of probable undeveloped reserves in the McDaniel Report with $61.6 million of associated undiscounted capital.

Significant Factors or Uncertainties Affecting Reserves Data

Our evaluated oil and gas properties have no significant risks or uncertainties beyond those which are inherent in the oil and gas industry. These risks and uncertainties include but are not limited to: commodity prices and exchange rates, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks that we face in this market. Our actual results, performance or achievements could differ materially from those expressed in, or implied by, these reserve estimates and accordingly, no assurance can be given that any of the forward-looking statements or estimates will transpire or occur or what benefits we can derive from them. The reader is cautioned not to place undue reliance on this forward-looking information.

We apply significant judgement in estimating the nature, amount and timing of abandonment and reclamation costs and the actual costs could change substantially in amount and timing from those estimated in this report and those reported in the financial statements for the nine months ended December 31, 2019.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The estimates are based on production forecasts, forecast prices and costs and future economic conditions.

Decommissioning Obligations

Amounts recorded for decommissioning obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of asset retirement, including well abandonment and well site reclamation.

The future estimated cash outflows required to settle the obligations have been discounted using a risk-free rate of 1.74% at December 31, 2019 (December 31, 2018 – 2.0%). The total undiscounted amount of future cash flows required to settle the obligation as estimated at December 31, 2019 was $31.8 million (December 31, 2018 - $32.4 million).

Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs

Abandonment, decommissioning and reclamation (“ADR”) costs for all wells (both existing and undrilled wells) that have been attributed reserves and certain dedicated facilities have been included in this Statement. This Statement of Reserves Data also includes ADR costs of any pipelines, non-dedicated facilities or for wells with no attributed reserves. This is a significant change to the prior years' practice, when ADR costs on inactive wells were not included in the reserves evaluation, a practice consistent with many other companies in the industry.

We estimate the amount and timing of future abandonment and reclamation expenditures for each well. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well site. The estimated expenditures are based on current regulatory standards, other public data and our own experience including actual abandonment and reclamation cost history.

Additional information on our decommissioning obligations, including abandonment and reclamation costs for all wells (those to which reserves have been attributed and those for which no reserves have been attributed) and facilities in which we hold an interest, can be found in the our Audited Financial Statements for the year ended December 31, 2019 and the accompanying Management Discussion and Analysis, which are available on SEDAR at www.sedar.com.

Future Development Costs

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

	FORECAST PRICES AND COSTS	
Year	Proved Reserves ($000's)	Proved + Probable Reserves ($000's)
2020	11,186	11,186
2021	26,348	54,964
2022	23,424	40,260
2023	19,245	22,827
2024	18,947	31,509
Remaining	49	49
Total (Undiscounted)	**99,199**	**160,796**

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop those reserves could have a negative impact on our future cash flow.

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

Other Oil and Natural Gas Information

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.

Wilson Creek

Wilson Creek is located 100 kilometres west of Edmonton, Alberta. We hold an average working interest of approximately 64 percent and are the operator of our production and working interest lands. The primary reservoirs are the Cardium oil resource play and liquids rich natural gas from deeper Cretaceous and Triassic formations. The key characteristic of the light oil resource play is 35° - 40° API oil, predictable geology and production profiles as well as consistent and repeatable economics. Liquids rich natural gas is produced from the Manville group of formations. During the second quarter of 2018, we drilled, completed, and equipped our first Cardium formation, operated, horizontal well, brought on-stream at Wilson Creek.

Windfall

Our Windfall property was acquired on January 4, 2018. We acquired a 50 percent working interest in the property for cash consideration of $3.4 million. The property is located 175 kilometres northwest of Edmonton, Alberta. The Windfall property is characterized as a light oil Bluesky channel of 36° - 40° API oil with associated natural gas production. During the year ended December 31, 2018, we became operator of the Windfall property with a 100% working interest through the acquisition of the operator, Bashaw. Subsequent to the drilling at Wilson Creek, we drilled the 1-3-59-15W5M well at Windfall. The 1-3 well was completed, equipped and placed on production in November 2018.

Northville/Pembina

Northville and Pembina fields are located 125 kilometres west of Edmonton, Alberta. We operate our production and lands with an average working interest of approximately 89 percent at Northville and 80 percent at Pembina. Both fields are characterized as liquids rich natural gas fields with production primarily coming from the Glauconite and Rock Creek formations. Natural gas production is processed at third party deep cut processing facilities resulting in natural gas liquids production of ethane, propane, butane and pentanes.

Niton

Our Niton property was acquired on February 22, 2019. We acquired a 96% working interest in the property as part of an acquisition of a group of assets from a private company for cash consideration of $0.6 million and 1.36 million common shares of Clearview. The property is located 160 kilometres west of Edmonton, Alberta. The Niton property is primarily focussed on the development of the Cardium formation producing light oil of 30° - 35° API oil with associated natural gas production. Additional oil is produced from the Ellerslie formation.

Garrington

The Garrington assets were also was acquired on February 22, 2019 as part of the acquisition of a group of assets from a private company. We acquired an average 94% working interest in the property. The property is located 100 kilometres north of Calgary, Alberta. Light oil production comes from the Cardium and Glauconitic formations, with additional liquids-rich gas production from the underlying Mississippian Elkton formation. The key characteristic of the light oil play is 35° - 40° API oil.

Other Properties

We have working interests varying from 0.05 percent to 100 percent in 8 other non-core fields and units producing oil and natural gas in central and southern Alberta. The majority of these properties are non-operated and are not actively being developed to grow production.

Oil and Natural Gas Wells and Unproved Properties

The following table summarizes, as at December 31, 2019, our interests in all producing and non-producing wells.

	Producing Wells (1)				Non-Producing Wells (1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	132	65.2	109	46.5	164	59.9	101	40.3
Saskatchewan	-	-	-	-	2	1.4	-	-
Total	132	65.2	109	46.5	166	61.3	101	40.3

Note:

(1) Does not include injection wells, service wells or abandoned wells. The Company has a working interest in 21 gross (5.2 net) water injection wells and 1 gross (0.09 net) service wells. The Company also has a working interest in 91 gross (49.4 net) abandoned but not yet reclaimed wells. An abandoned well is defined as fully cut and capped.

Properties with no Attributed Reserves

At December 31, 2019, our properties with no attributed reserves are approximately 82,266 gross undeveloped acres and 66,583 net undeveloped acres. All of the undeveloped land is in Alberta, Canada. We anticipate that approximately 3,573 net undeveloped acres of the mineral rights may expire before the end of the next fiscal year. We have executed on our strategy to acquire producing oil and natural gas properties on which there are significant in-fill and secondary recovery options for future development opportunities. There are no significant economic factors or uncertainties that affect the anticipated development or production activities on properties with no attributed reserves.

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 our operations. A variety of derivative instruments are used by us 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 may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 13 to our financial statements for the year ended December 31, 2019 and further disclosure on pages 11 and 12 of our MD&A for the year ended December 31, 2019.

Tax Horizon

Based on estimated 2020 cash flow and capital expenditures, we do not expect to be cash taxable in our fiscal year ended December 31, 2020. We currently estimate that we will not become taxable until at least 2025.

Costs Incurred

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

Expenditure	Twelve Months Ended December 31, 2019 (M$C)
Property acquisition costs – unproved properties (1)	7
Property acquisition costs – proved properties (2)	480
Exploration costs (3)	-
Development costs (4)	46
Other	1,422
Total	**1,955**

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The Company did not participate in the drilling of any wells in the year ended December 31, 2019.

In the upcoming fiscal year, our drilling and optimization program will be dependent on our ability to generate cash flow from operations and/or raise funds from other external sources. We are the operator of the majority of our lands and production which allows us to control the pace and location of our capital spending. We have no drilling commitments for the upcoming year.

Production Estimates

The following table sets out the volumes of working interest production before royalty deductions plus royalty interest production estimated for the year ended December 31, 2020, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Crude Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved				
Wilson Creek	161	1,353	78	464
Windfall	212	1,353	7	444
Northville	10	2,529	201	633
Pembina	31	652	67	206
Garrington	24	586	42	163
Niton	102	178	6	137
Others	232	1,027	45	450
Total	**772**	**7,678**	**446**	**2,497**

Total Proved + Probable				
Wilson Creek	170	1,378	79	479
Windfall	222	1,419	7	465
Northville	10	2,579	206	646
Pembina	31	731	75	227
Garrington	24	593	42	165
Niton	111	191	6	149
Others	235	1,052	46	457
Total	**803**	**7,943**	**461**	**2,588**

Production History

The following table indicates our average daily production (including production from our major areas) for the fiscal year ended December 31, 2019.

	Light and Medium Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Conventional Natural Gas (Mcf/d)	BOE (Boe/d)
Wilson Creek	160	83	1,308	461
Windfall	189	5	980	357
Northville	20	224	2,840	717
Pembina	29	75	748	229
Garrington	23	36	517	145
Niton	39	3	92	58
Others	224	35	1,142	454
Total	684	481	7,537	2,421

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

	March 31, 2019	June 30, 2019	September 30, 2019	December 31, 2019	Twelve Months Ended December 31, 2019
Average Daily Production (1)					
Light and Medium Crude Oil (bbls/d)	768	709	641	621	684
Natural Gas Liquids (bbls/d)	473	452	501	494	481
Conventional Natural Gas (MMcf/d)	7,646	7,153	7,487	7,859	7,537
Combined (boe/d)	2,515	2,353	2,389	2,426	2,421
Average Net Production Prices Received (1)					
Light and Medium Crude Oil ($/bbl)	62.49	69.12	63.04	64.03	64.69
Natural Gas Liquids ($/bbl)	32.85	26.19	20.45	23.87	25.69
Conventional Natural Gas ($/Mcf)	2.59	1.20	1.02	2.44	1.83
Combined ($/boe)	33.13	29.51	24.37	29.18	29.08
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	8.05	9.61	8.92	8.90	8.85
Natural Gas Liquids ($/bbl) (4)	3.79	3.68	0.44	1.87	2.41
Conventional Natural Gas ($/Mcf) (4)	0.09	0.04	0.04	0.05	0.05
Combined ($/boe)	3.51	3.76	2.59	2.86	3.18
Production Costs (2)(3)					
Light and Medium Crude Oil ($/bbl)	21.09	24.20	24.49	29.62	24.65
Natural Gas Liquids ($/bbl)	13.07	11.85	11.78	12.12	12.21
Conventional Natural Gas ($/Mcf)	2.18	1.98	1.96	2.02	2.04
Combined ($/boe)	15.51	15.55	15.17	16.59	15.71
Netback Received					
Light and Medium Crude Oil ($/bbl)	33.35	35.31	29.63	25.51	31.18
Natural Gas Liquids ($/bbl)	15.99	10.66	8.23	9.87	11.07
Conventional Natural Gas ($/Mcf)	0.33	(0.81)	(0.98)	0.37	(0.26)
Combined ($/boe)	14.11	10.20	8.23	9.73	10.19

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) Overhead recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(4) Natural gas liquids and natural gas royalties paid are net of Gas Cost Allowance credits.

OTHER BUSINESS INFORMATION

Specialized Skill and Knowledge

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

Competitive Conditions

The oil and natural gas industry is intensely competitive and we compete with a substantial number of other entities, many of which have greater technical or financial resources. However, we attempt to enhance our competitive position by operating in areas where we believe our technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that Clearview will be able to explore for and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

Our business is generally cyclical. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "*Risk Factors - Seasonality*".

Economic Dependence

We have various contracts in place with oil and gas marketers that purchase our production of oil, natural gas and natural gas liquids. We are not, however, economically dependent on any one contract as various other oil and gas marketers exist in the marketplace.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on our earnings and our overall competitiveness. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of the Company see "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

Employees

As at December 31, 2019, we employed or retained the services of 11 individuals (including personnel hired on a contract basis) at our head office in Calgary, Alberta. In addition, we retained the services of 11 individuals in field operations in various locations in Alberta as at December 31, 2019.

The Board adopted a Whistleblower Policy on August 22, 2018, establishing appropriate procedures for the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters, and for the confidential, anonymous submission of concerns regarding questionable accounting or auditing matters by employees.

Reorganizations

We have not completed any material reorganization within the three most recently complete financial years, or during this financial year. No material reorganization is currently proposed for the current financial year. See "*General Development of the Business*".

Environmental, Health and Safety Policies

We have a Reserves & HSE Committee and are sensitive to the environmental, health, safety and security consequences of our operations. Accordingly, we are in strict compliance with all applicable Federal and Provincial environmental laws and regulations. We have procedures in place for employees to discuss matters concerning particular environmental, health or safety regulations with a member of the Reserves & HSE Committee.

DIVIDENDS

We issued dividends to shareholders in January of each of 2013 to 2015, but no dividends have been paid since due to reduced cash flows as a result of low oil and natural gas prices. The Company does not currently have a dividend policy in place, and there is no assurance that it will do so in the future.

Payment of dividends in the future will be dependent on, among other things, cash flow, results from operations, the financial condition of the Company, credit facility covenants, the need for funds to finance ongoing operations and other considerations.

DESCRIPTION OF CAPITAL STRUCTURE

Our authorized share capital consists of an unlimited number of voting common shares (the "**Common Shares**") and an unlimited number of preferred shares issuable in series (the "**Preferred Shares**").

Common Shares

We are authorized to issue an unlimited number of Common Shares. Holders of the Common Shares shall be entitled to one vote per share at any meeting of shareholders. Subject to the rights of the holders of Preferred Shares, holders of Common Shares are entitled to dividends if and when declared by the Board upon liquidation, dissolution or winding-up to receive the remaining property of the Company.

Preferred Shares

We are authorized to issue an unlimited number of Preferred Shares, issuable in series. Holders of the Preferred Shares are not entitled to a vote at any meeting of shareholders, however they are entitled to receive notice and information documents regarding such meetings. Holders of Preferred Shares hold priority over holders of Common Shares upon a liquidation, dissolution, or winding-up of the Company. The Preferred Shares are redeemable at the option of the Company. As at the financial year ended December 31, 2019, no Preferred Shares of the Company have been issued.

Constraints

There are currently no constraints imposed on the ownership of our securities to ensure that we have a required level of Canadian ownership.

Ratings

We have not asked for, nor received, a stability rating, or to our knowledge, have received any other kind of rating, including a provisional rating from one or more approved rating organizations for our securities that are outstanding and which continue in effect.

MARKET FOR SECURITIES

Our securities are not traded or quoted on any Canadian or foreign marketplace. In the financial year ended December 31, 2019, the Company only had one share issuance:

Shareholder	Date of Issuance	Price of Issuance	Number of Common Shares
C Group Energy Inc.[(1)]	February 22, 2019	$6.516	1,361,542

Notes:

(1) For more information about this issuance, please see "*Description of the Business – General Development of the Business – Year ended December 31, 2019*".

ESCROWED SECURITIES AND SECURTIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To our knowledge, as of December 31, 2019, none of our securities are held in escrow or subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

The names, province or state, and country of residence, positions and offices held, as at the date of this document, and principal occupation of our directors and officers are set out below, and in the case of directors, the period each has served as our director.

Name, Province or State, and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Lindsey R. Stollery Markham, Ontario, Canada	*Director* *Board Chair*	Ms. Stollery is the Chief Investment Officer of Angus Glen and Kylemore Group of Companies, a position she has held since April of 2017. Ms. Stollery also holds the position of President of Pino Grande Holdings Corp. since October 2012; Vice President of AGS Capital Corp. since October 2012 (both private investment companies). Ms. Stollery earned her certificate with the Institute of Directors (UK) and from the Institute of Corporate Directors. Ms. Stollery owns 1,194,386 Common Shares, amounting to approximately 10.23% Common Shares of the Company. She is the President of Pino Grande Holdings Corp., which owns 984,141 Common Shares and she owns 210,245 Common Shares directly or indirectly through personal holding companies.	September 2013
Richard G. Carl Toronto, Ontario, Canada	*Director* *Audit Committee Chair*	Mr. Carl has served as one of our directors since 2011. During the preceding five years, Mr. Carl has served as President of AGS Capital Corp. (private family office) and Executive Chairman of Canada Fluorspar Inc. (mining). Mr. Carl has board experience in numerous capacities for both private and public companies where he has served in roles as Executive Chair, Audit and Compensation Committee Chairs as well as Chair of Special Committees in a range of industries including	January 2011

Name, Province or State, and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
	Compensation Committee Member	oil and gas, mining, financial services, power generation and real estate. Mr. Carl is a past director of Highpine Oil and Gas Ltd. where he chaired the audit committee and the special committee that led to the sale of Highpine to Daylight Resources Trust. Mr. Carl owns 68,253 Common Shares, amounting to approximately 0.58% of the issued and outstanding Common Shares of the Company.	
Timothy S. Halpen Calgary, Alberta, Canada	*Director* *Reserves & HSE Committee Chair*	Mr. Halpen, is a Professional Engineer and has been one of our directors since April 16, 2018. Mr. Halpen was a Director of Bashaw Oil Corp. from June 2015 until April 2018, as well as the Chief Operating Officer at Chinook Energy Inc. (a public oil and gas company) from May 2012 until April 2020. Mr. Halpen owns 6,340 Common Shares, amounting to approximately 0.05% of the issued and outstanding Common Shares of the Company.	April 2018
Todd L. McAllister Foothills, Alberta, Canada	*Director* *Audit Committee Member* *Compensation Committee Chair*	In addition to being one of our directors, Mr. McAllister has held executive roles at several private oil and gas companies, including serving as the President of Midvalley Capital Corp. since August 2012; President of 999853 Alberta Ltd. from October 2002 to July 2012; President of Dunvegan Hydrocarbons Ltd. from December 2002 to December 2004; and Vice President of Denim Energy Corp. from October 2000 to November 2002. Mr. McAllister obtained an Advanced Graduate Diploma in Management from Athabasca University in 2001. Mr. McAllister owns 330,500 Common Shares, amounting to approximately 2.83% of the issued and outstanding Common Shares of the Company.	September 2013
Harold F. Pine Denver, Colorado, U.S.A	*Director* *Compensation Committee Member*	Mr. Pine was appointed as one of our directors in April 2017. Mr. Pine has served as Senior Vice President of Denver and Senior Portfolio Manager of Denver at First Western Trust Bank until December 2014. Mr. Pine holds Master's degree in Computational Finance from University of Washington from 2014 to 2016, Masters of Business Administration in Finance from University of Colorado Boulder from 1994 to 1996 and BS in Finance from California State University-Sacramento. Mr. Pine owns 224,365 Common Shares, amounting to approximately 1.92% of the issued and outstanding Common Shares of the Company.	April 2017
Murray K. Scalf Calgary, Alberta, Canada	*Director* *Compensation Committee Member* *Reserves & HSE Committee Member*	Mr. Scalf served as our Executive Vice President from October 2010 to February 27, 2014 and has been one of our directors since June 28, 2016. Mr. Scalf has also previously served as Executive Vice President of Donnycreek Energy Inc., Vice President, Business Development at Donnybrook Energy Inc. and prior thereto, Mr. Scalf was President of Denim Exploration Corp., Denim Energy Inc. Dorchester Energy Inc., Dorado Energy Inc., and Deventa Energy Inc. (public and private oil and gas companies). Mr. Scalf has over 28 years of experience in the oil and gas industry. He has extensive experience in founding, building and selling junior exploration companies. Mr. Scalf is a Member of the Canadian Association of Petroleum Landmen.	June 2016

Name, Province or State, and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
		Mr. Scalf owns 73,506 Common Shares, amounting to approximately 0.63% of the issued and outstanding Common Shares of the Company.	
David M. Vankka Calgary, Alberta, Canada	*Director* *Audit Committee Member* *Reserves & HSE Committee Member*	Mr. Vankka has been one of our directors since June 28, 2016. Mr. Vankka is a Managing Director and Portfolio Manager at ICM Asset Management Inc., a position he has held since June 2016. He has also served as Managing Director of Energy Investment Banking at Canaccord Genuity Corp. from November 2012 to January 2016; as Managing Director of Investment Banking at Dundee Securities Ltd. from April 2011 to July 2012; as Vice President of Risk Management at Gluskin Sheff + Associates, Inc. from October 2009 until April 2011; and as Managing Director of Institutional Sales & Trading at Macquarie Tristone (formerly, Tristone Capital Inc.) for seven years. He has over 25 years of capital markets experience, with a strong background in institutional trading and investment banking, particularly in the oil and gas sector. He holds Bachelor of Commerce with distinction from the University of Calgary. Mr. Vankka is a Chartered Professional Accountant, Chartered Accountant, and a CFA charterholder. Mr. Vankka owns 48,500 Common Shares, amounting to approximately 0.42% of the issued and outstanding Common Shares of the Company.	June 2016
Tony Angelidis Calgary, Alberta, Canada	*President* *Chief Executive Officer*	Mr. Angelidis has been President and Chief Executive Officer of Clearview since April of 2018. Prior thereto, Mr. Angelidis was president and CEO of Bashaw Oil Corp. a role he entered after 34 years of experience in Western Canadian exploration and development. Prior to joining Clearview, Mr. Angelidis held a number of Director and Officer positions at other junior E&P companies. Most notably, as the Co-Founder of Delphi Energy Corp., Mr. Angelidis was a Director and Senior VP of Exploration. Mr. Angelidis was also the Co-Founder of both Renata Resources and Prize Energy, both high-growth E&P entities that were eventually sold to Rio Alto and Canadian Superior, respectively. Mr. Angelidis holds a Bachelor of Science in Geology from McGill University. Mr. Angelidis owns 15,762 Common Shares, amounting to approximately 0.14% of the issued and outstanding Common Shares of the Company.	N/A
Brian Kohlhammer Calgary, Alberta, Canada	*Vice President, Finance* *Chief Financial Officer*	Mr. Kohlhammer joined the Clearview team in April of 2018 from Bashaw Oil Corp. Prior to that, Mr. Kohlhammer was VP Finance and CFO at a number of other junior oil and gas companies, namely Delphi Energy Corp., Virtus Energy and Renata Resources Inc. Mr. Kohlhammer is a Chartered Professional Accountant, Chartered Accountant with more than 30 years of experience in financial reporting, financial analysis, budgeting, risk management, banking, public equity and debt markets and investor relations. Mr. Kohlhammer holds a Bachelor of Commerce degree from the University of Saskatchewan. Mr. Kohlhammer owns 29,552 Common Shares, amounting to approximately 0.25% of the issued and outstanding Common Shares of the Company.	N/A

Name, Province or State, and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since
Darcy Ries Calgary, Alberta, Canada	*Vice President, Engineering* *Chief Operating Officer*	Mr. Ries joined Clearview in April of 2018. Prior thereto Mr. Ries was VP Engineering at Bashaw Oil Corp. Prior to that, Mr. Ries was the COO for Grizzly Resources from 2015-17. Mr. Ries has previously held the position of Chief Reservoir Engineer and senior asset management roles at domestic and international energy companies. In 2014, Mr. Ries and team were awarded a Summit Award from The Association of Professional Engineers and Geoscientists of Alberta (APEGA); recognizing leadership and excellence in the practice of engineering and geoscience. Mr. Ries holds a Bachelor of Science in Chemical Engineering from the University of Saskatchewan. Mr. Ries owns 15,762 Common Shares, amounting to approximately 0.14% of the issued and outstanding Common Shares of the Company.	N/A

All of our directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholders' meeting called for election of directors, or on such other date as they may be removed from their position according to the ABCA. Each director will devote an appropriate amount of time as required to fulfill their obligations to us. Our officers are appointed by and serve at the discretion of the Board.

As of the date of this AIF, our directors and executive officers, as a group, beneficially owned, controlled, or directed, directly or indirectly, 2,006,926 Common Shares, or approximately 17.20% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date hereof, or was within ten years before the date hereof, 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 30 consecutive days (collectively, referred to as an "**Order**") that was issued while the director was acting in the capacity as director, chief executive officer or chief financial officer; or was subject to an Order that was issued after the director 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.

Bankruptcies

None of our directors, executive officer, or controlling shareholder (nor any personal holding company of any of such persons) is, as of the date hereof, or has been within the ten years before the date hereof, 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. Furthermore, none of our directors, executive officers, or controlling shareholders has within the ten years prior to the date hereof become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such director, executive officer or controlling shareholder.

Penalties or Sanctions

None of our directors, executive officers or controlling shareholders (nor any personal holding company of any of such persons) 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 that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

There are no legal proceedings we are or were a party to, or that any of our property is or was the subject of, during our fiscal year ended December 31, 2019, nor are any such legal proceedings known to us to be contemplated, that involve a claim for damages, exclusive of interest and costs, exceeding 10% of our current assets.

Regulatory Actions

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any: (a) of our directors or executives; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of our voting securities, except those listed below; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction; within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect us.

The only persons or companies who, to our knowledge, beneficially own, or control or direct, directly or indirectly, voting securities carrying 10% or more of the outstanding Common Shares are as follows:

Name	Approximate Number of Common Shares Held Directly or Indirectly	Approximate Percentage of outstanding Equivalent Common Shares
Pino Grande Holdings Corp (1)	984,141	8.43%
Lindsay R. Stollery. (1)	210,245	1.80%
C Group Energy Inc. (2)	1,361,542	11.67%

Notes:

(1) Based upon information provided to us by Ms. Stollery, a director of the Company. Ms. Stollery is the president of Pino Grande Holdings Corp. and has control and direction of the holdings of Pino Grande Holdings Corp. Ms. Stollery holds 210,245 Common Shares in her own name and indirectly through personal holding companies.

(2) On February 22, 2019, C Group Energy Inc. sold certain assets to us in exchange for cash consideration and 1,361,542 Common Shares. For more details about this transaction, please see "*Description of the Business – General Development of the Business – Year ended December 31, 2019*".

AUDITOR, TRANFER AGENT, AND REGISTRAR

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

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada, 8th Floor, 100 University Avenue, Toronto, Ontario M5J 2Y1.

MATERIAL CONTRACTS

We are not currently committed to any material contracts.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made by us under National Instrument 51-102 during, or relating to our most recently completed financial year and whose profession or business gives authority to such report, valuation, statement or opinion, are:

- KPMG LLP, our independent auditors; and
- McDaniel, our independent reserve evaluator.

Interests of Experts

To our knowledge, no registered or beneficial interests, direct or indirect, in any of our securities or other property or of one of our associates or affiliates (i) were held by McDaniel or by the "designated professionals" (as defined in Form 51-102F2) of McDaniel, when McDaniel prepared the McDaniel Report,

(ii) were received by McDaniel or the designated professionals of McDaniel after McDaniel prepared the McDaniel Report, or (iii) is to be received by McDaniel or the designated professionals of McDaniel.

Neither McDaniel nor any director, officer or employee of McDaniel is or is expected to be elected, appointed or employed as one of our directors, officers or employees.

KPMG LLP has advised us that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

INDUSTRY CONDITIONS

The business of exploration, development, and acquisition of oil and gas reserves involves financial, operational and regulatory risks inherent in the oil and gas industry, several of which are beyond our control, which may impact our results. These risks are operational, financial and regulatory in nature.

Our revenues, profitability, future growth and the carrying value of our properties are substantially dependent on prevailing prices of oil and natural gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to volatility in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control.

Our activities expose us to a variety of financial risks that arise from our exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk. Presented below is information about our exposure to each of the above risks. We employ risk management strategies and polices to ensure that any exposure to risk complies with our business objectives and risk tolerance levels. We manage commodity price risks by focusing our acquisition program on areas that will generate attractive rates of return even at substantially lower commodity prices than those prices being received at the time of the acquisition.

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, including global events such as the outbreak of COVID-19. 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. Worldwide oversupply of crude oil, a lack of available storage capacity and dramatically decreased demand due to the COVID-19 pandemic have driven crude oil prices to historic lows in 2020. OPEC and other oil producing countries announced an agreement to cut production by approximately 10 million bbls/d on April 12, 2020, in an effort to stabilize global oil markets.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. 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 price of condensate and other natural gas liquids such as ethane, butane and propane ("**NGLs**") sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, 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.

Export crude oil, natural gas and NGLs from Canada are subject to 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 licenses. 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 a 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 m3 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.

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. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects 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

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

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the CER and the cabinet of the federal government. 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 as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. 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.

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. While 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, other companies 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. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, 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.

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.

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.

The Corporation is not currently 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. Under the terms of NAFTA, 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 were 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.

On November 30, 2018, U.S. President Donald Trump, Prime Minister Trudeau, and outgoing Mexican President Enrique Pena Nieto signed an authorization for a new trade deal to replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). As of March 13, 2020, each of Canada, the United States and Mexico have ratified the USMCA and it will come into force on June 1, 2020. Until then, NAFTA will continue to govern trade relations among Canada, Mexico, and the United States. 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 USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Article 605 of NAFTA (the proportionality clause) has historically prevented Canada from reducing oil and gas exports to the United States and Mexico relative to the total supply produced in Canada. Despite reducing crude oil production, the Government of Alberta's curtailment program has been compliant with NAFTA due to the operation of the proportionality rule. Reducing Canadian supply reduced Canada's required offering, thereby allowing Alberta to reduce production without causing Canada to breach its export obligations. However, the USMCA does not contain the proportionality rules of 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 oil and gas products to the European Union. Although CETA remains subject to ratification by certain 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 oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

The provincial government (i.e. the Crown), predominantly owns the mineral rights to crude oil and natural gas located in the Province of Alberta. The provincial government 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

Province conducts 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. The 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.

On March 20, 2020, the Government of Alberta announced that all Crown mineral agreements with an expiration date in 2020 will be extended for one year, in response to the economic stress on Alberta's oil and natural gas producers caused by the COVID-19 pandemic. See "Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry".

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

The Province of Alberta has 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. Additionally, the province has shallow rights reversion for 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 Alberta. Approximately 19% 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. The Company currently has two non-producing wells on land governed by the IOGC.

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 governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical 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 are often 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 totaling $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, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. 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% 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 also 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.

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.

In addition to the royalties payable to the mineral owners, 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.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, 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 terms.

Regulatory Authorities and Environmental Regulation

General

The 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 and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, 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. However, such conflicts are uncommon. 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 Impact Assessment Agency of Canada (the "**IA Agency**") replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. No hearing date has been set for the case, however it 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 single regulator responsible for all resource development in Alberta. 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 Alberta 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.

On March 20, 2020, the Government of Alberta announced a $113 million contribution to the AER's industry levy, intended to provide financial relief in response to the economic stress and uncertainty facing Alberta's oil and natural gas industry as a result of the COVID-19 pandemic. In April 9, 2020, the Government of Alberta announced that Alberta Energy is deferring all public land sales and direct purchases of petroleum and natural gas and oil sands mineral rights for a minimum of 90 days, in response to the COVID-19 pandemic. The AER has suspended reporting requirements under the Coal Conservation Act, the OGCA, and the OSCA until August 14, 2020, and Alberta Environment and Parks has suspended most reporting requirements relating to approvals or registrations in the EPEA, licenses and approvals in the Water Act, and formal dispositions in the Public Lands Act. However, the obligation to monitor and collect data normally reported within any such approvals remains in place and subject to enforcement, as does the obligation to report emergencies, contraventions, releases and other incidents. See "Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry".

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 Alberta Environment and Parks, Alberta Energy, the Policy Management Office, 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 and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

On April 17, 2020, as part of an announcement of federal relief for Canada's oil and natural gas industry in response to the COVID-19 pandemic, the federal government pledged $1.7 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Alberta

The AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. In early March 2020, the Government of Alberta announced an extension of an existing $235 million loan to the Orphan Fund by up to $100 million, earmarked for decommissioning approximately 1,000 wells and initiating reclamation on 1,000 sites.

The AER previously assessed the liability management rating ("**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 Alberta 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 Alberta 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 Alberta LMR Program may affect the Company's ability to obtain or transfer licenses.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees had the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, 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 amended *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have 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 are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a LMR, being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada's *Redwater* decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

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 by 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. On April 9, 2020 the AER suspended the compliance deadline for the final year of the IWCP under Directive 013 for inactive wells under the IWCP, in response to the COVID-19 pandemic.

As part of its strategy to encourage the decommissioning of inactive or marginal oil and 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 while enabling participants to meet their liability reduction targets. We are participating in the voluntary ABC program.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as 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 cash 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 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 2018, 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, 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.

Seven provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, the Northwest Territories, and Newfoundland. The federal fuel charge regime took effect in Saskatchewan, Manitoba, and Ontario 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. While New Brunswick was previously subject to the federal fuel charge, the federal government agreed to recognize the equivalency of New Brunswick's proposed fuel charge in December 2019. The New Brunswick fuel charge will take effect on April 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. The Court was set to hear the appeals in March 2020, but they have been tentatively postponed until June 2020 due to the COVID-19 pandemic. 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. 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 its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. 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 "highperformance" 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 TIERregulated 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.

On March 30, 2020, the Government of Alberta extended the deadlines to submit compliance reports and emissions reduction plans from March 31, 2020 to June 30, 2020.

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 over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. 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.

Accountability and Transparency

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

RISK FACTORS

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

Public Health Crises

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the current COVID-19 (coronavirus), may adversely affect the Corporation.

The Corporation's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a public health emergency of international concern, and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. Reactions across the globe to the spread of COVID-19 have led to, among other things, significant restrictions on travel, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread from China throughout Europe, the Middle East, Canada and the United States, amongst other countries, causing cities, provinces, states, countries and specific companies to impose unprecedented restrictions such as quarantines, business closures, shelter in place declarations and travel restrictions, amongst other measures in an attempt to slow the spread of COVID-19. While these effects are expected to be temporary, the duration of the business disruptions domestically and internationally and related financial impact cannot be reasonably estimated at this time and may last for an extended period of time. Similarly, the Corporation cannot estimate whether or to what extent the COVID-19 outbreak and the potential financial impact may extend to countries outside of those currently most heavily impacted. Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*". The risks to the Company of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact the Company is uncertain; however, it is possible that COVID-19 may have a material adverse effect on our business, results of operations and financial condition.

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect the Company by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (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.

Should an employee or visitor in any of our facilities, offices or work sites become infected with a serious illness that has the potential to spread rapidly, this could place our workforce at risk. The current COVID-19 pandemic is one example of such an illness. We are taking every precaution to strictly follow industrial hygiene and occupational health guidelines. Additionally, we follow posted health guidelines, as and when posted, to protect the health of its employees and decrease the potential impact of serious illness on its operations. There can be no assurance that this virus or another infectious illness will not impact the our personnel and ultimately our operations.

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

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations, such as the current COVID-19 (coronavirus), may adversely affect the Corporation.

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, state or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Corporation, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses including, most recently, the COVID-19 pandemic, domestic and global trade disruptions, infrastructure disruptions, civil disobedience or unrest (including the most recent protests and railway blockades in Canada), natural disasters, national emergencies, acts of war, technological attacks and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Corporation, its customers, and/or either of their businesses or operations, which may have a material adverse effect on the Corporation's reputation, business, financial conditions or operating results.

Exploration, Development and Production Risks

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

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. 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 continue to find satisfactory properties to acquire or participate in. Moreover, 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 as well as 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 and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels 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, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, 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 maintains liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs.

Weakness in the Oil and Gas Industry

Weakness and volatility in market conditions for the oil and gas industry may affect the value of our reserves, restricting cash flow and its ability to access capital to fund development of property.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions, sovereign debt levels, weakening global relationships, world health emergencies (including the COVID-19 pandemic), and political upheavals in various countries including growing anti-fossil fuel sentiment have caused significant weakness and volatility in commodity prices.

Through the first few months of 2020, oil prices deteriorated due to softening global demand caused by the COVID-19 pandemic. In March 2020, OPEC and Russia were unable to reach an agreement to further reduce oil production in response to the COVID-19 pandemic. Saudi Arabia responded by reducing its pricing and promising to increase production to over 10 million bbl/day. These actions led to the deepest drop in crude oil prices that global markets have seen since 1991. With the rapid spread of COVID-19 and additional oil supply expected to come on-stream over the near term, oil prices and global equity markets have deteriorated significantly and are expected to remain under pressure. The extreme supply / demand imbalance is anticipated to cause a reduction in industry spending in 2020.

These events and conditions have caused a significant decrease 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. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada.

Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict our cash flow resulting in less funds from operations being available to fund our capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. 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 gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

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

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. Our ability to market our oil and natural gas may depend upon our ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect our business.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. 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.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas production, development and exploration activities. 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 operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. 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.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect our financial condition, results of operations and cash flow.

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 devices 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. In addition, advancements in energy efficient products have a similar effect on the demand for oil and 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 by decreasing our profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Reserves Estimates

Our estimated proved and proved + probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect our business.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the 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. 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 cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from 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 cash flows 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on our ability to produce and sell its oil and natural gas.

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of 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 limit the ability to transport produced oil and gas to market. 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. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. 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 cash flows. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the CERA and the *IIA* came into force, and the NEB and the *CEAA 2012* were repealed. The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals of major projects, is unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of our production may, from time to time, be processed through facilities owned by third parties. 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 its production and deliver the same for sale. 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.

Substantial Capital Requirements

Our access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

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 current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

We may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

Cash flow 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 its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and 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 gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If 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.

Credit Facility Arrangements

Failing to comply with covenants under our credit facilities could result in restricted access to capital or being required to repay all amounts owing thereunder.

We currently have a covenant-based credit facility which includes certain financial ratio tests. These financial ratio tests, from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our credit facility, which could require us to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our credit facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

If our lender requires repayment of all or portion of the amounts outstanding under its credit facility for any reason, including for a default of a covenant, 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 its 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 lender could proceed to foreclose or otherwise realize upon the collateral granted to it to secure the indebtedness.

Regulatory

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

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. 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. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact our operations, which may affect our profitability. See "Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations".

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

Political Uncertainty

Our business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere.

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 gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project and other infrastructure projects.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which among other things, significantly reduced US corporate tax rates. This may affect relative competitiveness of other jurisdictions, including Canada. Additionally, the North American Free Trade Agreement was replaced by the United States-Mexico-Canada Agreement (the "**USMCA**") on November 30, 2018. See "*Industry Conditions – The North American Free Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to the reduction of regulations 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 the Company.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. 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. 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 its Common Shares.

Project Risks

The success of our operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges.

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the 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 and may be unable to market the oil and natural gas that it produces effectively.

Competition

We compete with other oil and natural gas companies, some of which have greater financial and operational resources

The junior oil and gas market 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 us. 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 us. 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.

Market Price

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

The trading price of 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 gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and 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 the Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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 those of the Company. The integration of acquired businesses 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 assets required to provide such services. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets may realize less on disposition than their carrying value on our financial statements.

Operational Dependence

The successful operation of a portion of our properties is dependent on third parties.

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

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

Reliance on Royalty Payors

A portion of our revenues from royalty payors and certain of its operations are dependent on the financial and operational capacity of third party working interest owners to develop and produce from our properties, over which we have limited influence.

We rely on other companies drilling and producing from lands in which we have a royalty interest. We have very limited ability to exercise influence over the decision of companies to drill and produce from such lands. Our return on lands in which we have a royalty interest depends upon a number of factors that may be outside of our control, including, but not limited to, the capital expenditure budgets and financial resources of the companies who have a working interest in such lands, the operator's ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may have a working interest in the lands in which we have a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. In addition, weak commodity prices might result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which we have a royalty interest will negatively affect our cash flows and financial results.

Financial difficulty of companies who have lands in which we have a royalty interest may affect our ability to collect royalty payments, especially if such companies go bankrupt, become insolvent, or make a proposal or institute any proceedings relating to bankruptcy or insolvency.

Cost of New Technologies

Our ability to successfully implement new technologies into our operations in a timely and efficient manner will affect our ability to compete.

Our 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 enjoy technological advantages and may in the future allow them to implement new technologies before us. 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 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.

Royalty Regimes

Changes to royalty regimes may negatively impact our cash flows

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. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting our financial position.

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 its reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator ("**AER**") announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. Pursuant to an earthquake approximately 12km south of Sylvan Lake on March 4, 2019, measuring 4.1 local magnitude (M_L), the AER recommends that oil and gas operators working in the Duvernay Formation in the Red Deer Region take similar steps to reduce the possibility of triggered seismicity. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in our operations may increase our costs of compliance or subject us to regulatory penalties or litigation

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

Environmental

Compliance with environmental regulations requires the dedication of a portion of our financial and operational resources.

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, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and 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.

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 will be 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

Taxes on carbon emissions affect the demand for oil and natural gas, our operating expenses and may impair our ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with our ability to acquire properties or require a substantial cash deposit with the regulator.

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. 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 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. In 2016, the Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal. This decision was appealed to the Supreme Court of Canada, which overturned the holding by the Alberta Court of Appeal. The Supreme Court holds that there is no operational conflict between the abandonment and reclamation provisions contained in Alberta's 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 license 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 court decision, the AER issued interim rules to administer the liability management program. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, in response to the Supreme Court's final ruling. The AER may make further rule changes at any time. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs.

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions.

Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. 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. In addition, 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. Given the evolving nature of the debate related to climate change 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 reducing the demand for oil and gas production resulting in a decrease in our profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect our financial condition

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States 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 its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our Common Shares.

Issuance of Debt

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

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.

Hedging

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

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 the Company from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, 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;
- the 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.

Availability of Drilling Equipment and Access

Restrictions on the availability of and access to drilling equipment may impede our exploration and development activities.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to us and may delay exploration and development activities.

Title to Assets

Defects in the title to our properties may result in a financial loss.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. Our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue we receive.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on us.

Our involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural 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.

Geopolitical Risks

Global political events may adversely affect commodity prices which in turn affect our cash flow.

Political events throughout the world that cause disruptions in the supply of oil continuously affect 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 the parties in power, 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.

Eco-Terrorism Risks

Our properties may be subject to terrorist attack.

Our oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Reputational Risk Associated with our Operations

We rely on our reputation to continue our operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by our operations could damage our reputation in the areas in which we operate. Negative sentiment towards the Company could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for us to operate our business and in residents in the areas where we do business opposing further operations in the area. 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 consultant to operate our business. Further, our reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which we have no control. In addition, environmental damage, loss of life, injury or damage to property caused by our operations could result in negative investor sentiment towards the Company, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

Changing investor sentiment towards the oil and gas industry may impact our access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and 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 the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Company, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Dilution

We may issue additional Common Shares, diluting current Shareholders

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

Management of Growth

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

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

Expiration of Licenses and Leases

We may fail to meet the requirements of a licence or lease, causing its termination or expiry.

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

Dividends

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

The amount of future cash dividends we pay, if any, will be subject to the discretion of the Board and may vary depending on a variety of 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 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 from time to time could be updated or revisited and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may be impacted 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 we make to finance capital expenditures using funds from operations.

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

Litigation

We may be involved in litigation in the course of our normal operations and the outcome of the litigation may adversely affect us and our reputation.

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, relating 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 the Company, and as a result, 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.

Intellectual Property Litigation

Unauthorized use of intellectual property may cause us to engage in or be the subject of litigation.

Due to the rapid development of oil and gas technology, in the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that we have infringed the intellectual property rights of others or commenced lawsuits against others who we believe are infringing upon our intellectual property rights. Our involvement in intellectual property litigation could result in significant expenses, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, we may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on our business and financial results.

Aboriginal Claims

Aboriginal claims may affect the Company.

Aboriginal 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 which could have a material adverse effect on our business and financial results.

Breach of Confidentiality

Breach of confidentiality by a third party could impact our competitive advantage or put us at risk of litigation.

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

Income Taxes

Taxation authorities may reassess our tax returns.

We file all required income tax returns and believes that we are in full compliance with the provisions of the *Tax Act* and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, 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 our business. Furthermore, tax authorities having jurisdiction over the Company may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and we may experience significant operational delays as a result.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. 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 swampy terrain. 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 are exposed to credit risk of third party operators or partners of properties in which we have an interest.

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 and of 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 the Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Conflicts of interest may arise for our directors and officers who are also involved with other industry participants

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 of 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 the Company 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*".

Reliance on Key Personnel

Loss of key personnel could negatively impact our operations

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may 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 its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Information Technology Systems and Cyber-Security

Breaches of our cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position

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 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. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; 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. 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

Expansion of our business exposes us to new risks and uncertainties

The operations and expertise of our management is currently focused primarily on oil and 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, may acquire different energy related assets and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading "Forward-Looking Statements" of this AIF.

AUDIT COMMITTEE INFORMATION

The Audit Committee has been structured to comply with the requirements of National Instrument 52-110. The Board has determined that the Audit Committee members have the appropriate level of financial understanding and industry-specific knowledge to be able to perform their duties. A copy of the Audit Committee mandate and the additional disclosure required under National Instrument 52-110 is attached to our information circular dated April 23, 2020 as Appendix "A".

The members of the Audit Committee are Mr. Richard G. Carl (Chair), Mr. Todd L. McAllister and Mr. David M. Vankka. Each member of the audit committee is independent and financially literate within the meaning of NI 52-110.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at www.sedar.com, or on our website at www.clearviewres.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans is contained in our information circular for our most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in our financial statements and the related management's discussion and analysis for our most recently completed financial year.

SELECTED ABBREVIATIONS

In this Annual Information Form, unless otherwise indicated or the context otherwise requires, the following abbreviations shall have the meaning set forth below:

Crude Oil and Natural Gas Liquids

Bbls/d	barrels of oil per day
Bbls or Bbl	barrels of oil
Boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
$/Bbl	Canadian dollars per barrel of oil
$/Boe	Canadian dollars per barrel of oil equivalent
Mbbls	thousand barrels
MBoe	thousand barrels of oil equivalent
Mbbls/d	thousand barrels of oil per day
MMbbls	million barrels of oil
MMboe	million barrels of oil equivalent
MMboe/d	million barrels of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Bcf	billion cubic feet
cf	cubic feet
Mcf	thousand cubic feet

Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	million cubic feet of gas equivalent
MMcfe/d	million cubic feet of gas equivalent per day
$/Mcf	Canadian dollars per thousand cubic feet
$/MMbtu	Canadian dollars per million British thermal units
GJ	Gigajoule
GJs/d	Gigajoules per day
$/GJ	Canadian dollar per gigajoule

Other

km	Kilometres
km2	square kilometres
$, Cdn, Cdn or $dollars	Canadian dollars
$000s or M$	thousand dollars
NEBC	north east British Columbia
MM$	million dollars
$US or US$	United States dollars
2D	two dimensional
3D	three dimensional
Vol/d	volumes per day

SELECTED CONVERSIONS

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	28.320
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Annual

Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In addition, this Annual Information Form may contain forward-looking statements and forward-looking information attributed to third-party industry sources.

In particular, this Annual Information Form contains, without limitation, forward-looking statements pertaining to the following:

- our ability to achieve our business strategy;
- our long-term growth strategy and implementation of such through a disciplined acquisition, development and production optimization program in Canada;
- the reserve potential of and production from our assets;
- the continuation of credit facilities currently in use by the Company;
- our estimates of future interest and foreign exchange rates;
- our environmental considerations;
- our expectations regarding commodity prices;
- the timing of commencement of certain of our operations, and the levels of production anticipated;
- supply and demand fundamentals in the oil and natural gas market;
- the effects of the COVID-19 pandemic;
- our access to adequate pipeline capacity and third-party infrastructure;
- our drilling plans, recompletion plans, and abandonment and reclamation costs;
- industry conditions pertaining to the oil and gas industry;
- our plans for, and results of, exploration and development activities;
- the timing of regulatory approvals regarding our undeveloped reserves;
- treatment of the Company under governmental regulatory regimes and tax laws;
- our expectations regarding having adequate human resource staffing;
- our dividend policy; and
- the number of wells we intend to drill, and drilling rigs we intend on operating, in 2019.

With respect to forward-looking statements and forward-looking information contained in this Annual Information Form, assumptions have been made regarding, among other things:

- our ability to obtain experienced and qualified staff in a timely and cost-efficient manner;
- the regulatory framework in the jurisdictions in which we conduct our business;
- geological and engineering estimates in respect of our reserves;
- our ability to market production of oil and natural gas successfully to customers;
- our future production levels;
- the applicability of technologies for recovery and production of our reserves;
- the recoverability of our reserves;
- future capital expenditures we intend on making;
- future cash flows from production;
- future sources of funding for our capital program;
- future debt levels;
- geological and engineering estimates in respect of our reserves;
- the geology of the areas in which we conduct exploration and development activities; and
- the impact of our competition.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form, including:

- our status and stage of development;

- general economic and market conditions;
- risks related to the exploration, development and production of oil and natural gas reserves;
- competition for, among other things, capital, the acquisition of reserves and resources, and skilled personnel;
- the availability of capital on terms favourable and acceptable to us;
- risks inherent in the exploration, development and production of oil and natural gas;
- actions by governmental authorities, including changes in regulation and taxation;
- environmental risks and hazards;
- political risks;
- the impact of COVID-19;
- failure to meet the specific requirements of certain licenses or leases;
- claims made in respect of our properties or assets;
- unforeseen title defects;
- risks arising from future acquisition activities;
- potential conflicts of interest;
- the potential for management assumptions and estimates to be inaccurate;
- the absence of an existing public market of our Common Shares;
- potential losses stemming from disruptions in production, including work slowdowns or stoppages, other labour difficulties, or disruptions in our transportation network;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- current global financial conditions, including fluctuations in interest rates and foreign exchange rates; and
- other factors discussed under "*Risk Factors*" in this Annual Information Form.

Without limitation of the foregoing, future dividend payments, if any, and the level thereof is uncertain, as our dividend policy and the funds available for the payment of dividends from time to time will be dependent upon, among other things, free cash flow, financial requirements for our operations and the execution of our growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond our control. Further, our ability to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Forward-looking statements and other information contained herein concerning the oil and gas industry and our general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis, and on assumptions based on data and knowledge of this industry. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. The industry involves risks and uncertainties and is subject to change based on various factors.

In addition, information and statements in this Annual Information Form relating to "reserves" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See also "*Certain Reserves Data Information*" below. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

Additional information on these and other factors that could affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

The forward-looking statements in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. We do not undertake any obligation to publicly update or revise any forward-looking statements except as expressly required by securities laws.

NON-GAAP FINANCIAL STATEMENTS

This Annual Information Form and certain documents incorporated by reference herein make reference to certain financial measures that are not recognized by GAAP. Non-GAAP financial measures do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. Investors are cautioned that these non-GAAP financial measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. The Financial Statements and MD&A are available on SEDAR at www.sedar.com.

CERTAIN RESERVES DATA INFORMATION

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible 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 qualitative certainty levels referred to in the definitions of proved, probable and possible reserves are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- 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 + probable reserves.

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

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

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 nonproducing. 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.

In this Annual Information Form:

- the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent the fair market value of reserves;

- there is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided in this Annual Information Form are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGL reserves may be greater than or less than the estimates provided in this Annual Information Form;

- the estimates of reserves and future net revenue 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; and

Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf : 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Appendix "A"

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

To the board of directors of Clearview Resources 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 + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	March 18, 2020	Canada	-	$148,428	-	$**148,428**

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

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

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd. Calgary, Alberta, Canada, March 19, 2019.

(signed) *"Jared Wynveen"*

Jared Wynveen, P. Eng.
Executive Vice President

Appendix "B"

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

Management of Clearview Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators; (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information; (b) the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and (c) the content and filing of this report.

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

(signed) *"Tony Angelidis"*
Tony Angelidis
President and Chief Executive Officer

(signed) *"Tim Halpen"*
Tim Halpen
Director, Chair of the Reserves & HSE Committee

(signed) *"Brian Kohlhammer"*
Brian Kohlhammer
Vice President, Finance and Chief Financial Officer

(signed) *"Murray Scalf"*
Murray Scalf
Director, Member of the Reserves & HSE Committee

Appendix "C"

CLEARVIEW RESOURCES LTD.
MANDATE OF THE BOARD OF DIRECTORS

The board of directors (the "**Board**") of Clearview Resources Ltd. ("**Corporation**" or "**Clearview**")) directly, and through its committees is responsible for the stewardship of the Corporation. In discharging its responsibility, the Board will exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances and will act honestly and in good faith with a view to the best interests of Clearview. In general terms, the Board will:

- in consultation with the chief executive officer of the Corporation (the "**CEO**"), define the principal objectives of Clearview;
- supervise the management of the business and affairs of Clearview with the goal of achieving Clearview's principal objectives as defined by the Board;
- discharge the duties imposed on the Board by applicable laws; and
- for the purpose of carrying out the foregoing responsibilities, take all such actions as the Board deems necessary or appropriate.

Without limiting the generality of the foregoing, the Board will perform the following duties:

Strategic Direction and Capital and Financial Plans

- require the CEO to present annually to the Board a long range strategic plan and a short range business plan for Clearview's business, which plans must:
    - be designed to achieve Clearview's principal objectives;
    - identify the principal strategic and operational opportunities and risks of Clearview's business; and
    - be approved by the Board as a pre-condition to the implementation of such plans;
- review progress towards the achievement of the goals established in the strategic, operating and capital plans;
- identify the principal risks of Clearview's business and take all reasonable steps to ensure the implementation of the appropriate systems to manage and mitigate these risks;
- approve the annual operating and capital plans;
- approve acquisitions and dispositions in excess of pre-approved expenditure limits established by the Board;
- approve the establishment of credit facilities;

- approve issuances of additional common shares, other securities and other instruments; and
- approve the repurchase of common shares in accordance with applicable securities laws.

Monitoring and Acting

- monitor Clearview's progress towards achieving its goals, and to revise and alter its direction through management in light of changing circumstances;
- monitor overall human resources policies and procedures, including compensation and succession planning;
- appoint the CEO and determine the terms of the CEO's employment with Clearview;
- approve any payment of dividends;
- ensure systems are in place for the implementation and integrity of Clearview's internal control and management information systems;
- evaluate the performance of the CEO on an ongoing basis through the in camera session held at the end of each regularly scheduled Board meeting;
- in consultation with the CEO, establish the limits of management's authority and responsibility in conducting Clearview's business;
- in consultation with the CEO, appoint all officers of Clearview and approve the terms of each officer's employment with Clearview;
- develop a system under which succession to senior management positions will occur in a timely manner;
- approve any proposed significant change in the management organization structure of Clearview;
- approve all retirement plans for officers and employees of Clearview;
- in consultation with the CEO, establish and maintain a disclosure and trading policy for Clearview; and
- generally provide advice and guidance to management.

Finances and Controls

- review Clearview's systems to manage and mitigate the risks of Clearview's business and, with the assistance of management, Clearview's auditors and others (as required), evaluate the appropriateness of such systems;
- monitor the appropriateness of Clearview's capital structure;

- ensure that the financial performance of Clearview is properly reported to shareholders, other security holders and regulators on a timely and regular basis;

- in consultation with the CEO, establish the ethical standards to be observed by all officers and employees of Clearview and use reasonable efforts to ensure that a process is in place to monitor compliance with those standards;

- require that the CEO institute and monitor processes and systems designed to ensure compliance with applicable laws by Clearview and its officers and employees;

- require the CEO institute, and maintain the integrity of, internal control and information systems, including maintenance of all required records and documentation;

- approve material contracts to be entered into by the Corporation;

- recommend to shareholders of Clearview a firm of chartered accountants to be appointed as Clearview's auditors;

- ensure Clearview's oil and gas reserve and/or resource report fairly represents the quantity and value of corporate reserves and/or resources in accordance with generally accepted engineering principles and applicable securities laws; and

- take reasonable actions to gain reasonable assurance that all financial information made public by Clearview (including Clearview's annual and quarterly financial statements) is accurate and complete and represents fairly the Corporation's financial position and performance.

Governance

- facilitate the continuity, effectiveness and independence of the Board by, amongst other things:

    - appointing a Board Chair;

    - appointing from amongst the directors an audit committee and such other committees of the Board as the Board deems appropriate;

    - defining the mandate of each committee of the Board;

    - ensuring that processes are in place and are utilized to assess the effectiveness of the Board Chair, the Board as a whole, each committee of the Board and each director; and

    - establishing a system to enable any director to engage an outside adviser at the expense of Clearview;

- review annually the composition of the Board and its committees and assess directors' performance on an ongoing basis, and propose new members to the Board; and

- review annually the adequacy and form of the compensation of directors.

Delegation

- the Board may delegate its duties to, and receive reports and recommendations from, any committee of the Board to the extent permitted by the *Business Corporations Act* (Alberta).

Composition

- the Board should be composed of at least 3 individuals elected by the shareholders at the annual meeting;
- a majority of Board members should be "independent" directors (within the meaning of National Instrument 58-101) and free from any business or other relationship that could impair the exercise of independent judgment;
- members should have or obtain sufficient knowledge of Clearview and the oil and gas business to assist in providing advice and counsel on relevant issues; and
- Board members should offer their resignation from the Board to the Board Chair following:
    - change in personal circumstances which would reasonably interfere with the ability to serve as a director;
    - change in personal circumstances which would reasonably reflect poorly on Clearview(for example, finding by a Court of fraud, or conviction under Criminal Code or securities legislation); and
    - if applicable, should a Board member receive a greater number of votes "withheld" from his or her election than votes "for" his or her election.

Meetings

- the Board shall meet at least four times per year and/or as deemed appropriate by the Board Chair;
- the Board shall meet at the end of its regular quarterly meetings without members of management being present;
- minutes of each meeting shall be prepared;
- the CEO and Chief Financial Officer shall be available to attend all meetings of the Board upon invitation by the Board; and
- Vice-Presidents and such other staff as appropriate to provide information to the Board shall attend meetings at the invitation of the Board.

Authority

- the Board shall have the authority to review any corporate report or material and to investigate activity of Clearview and to request any employees to cooperate as requested by the Board; and
- the Board may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Clearview.