ZARGON OIL & GAS LTD.

2019 ANNUAL INFORMATION FORM

March 17, 2020

TABLE OF CONTENTS

GLOSSARY OF SELECTED TERMS

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

Entities

Board of Directors means our board of directors.

Debenture Trustee means Computershare Trust Company of Canada.

Shareholders mean holders of Common Shares.

TSX means Toronto Stock Exchange.

Zargon, **we**, **us** or **our** means Zargon Oil & Gas Ltd. and its controlled entities on a consolidated basis, and where the context requires, also means our predecessor issuer, Zargon Energy Trust and its controlled entities on a consolidated basis prior to the completion of the Arrangement.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated January 24, 2019 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to our oil and natural gas assets at December 31, 2019.

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

Securities and Other Terms

Arrangement means the arrangement involving, among others, us and Zargon Energy Trust which commenced on December 31, 2010 and was completed on January 1, 2011.

Credit Agreement means the credit agreement dated as of January 1, 2011 as amended, which was repaid and terminated in 2016.

Common Shares means our issued and outstanding common shares.

Consolidation means the consolidation of all of our issued and outstanding Common Shares on the basis of twenty pre-consolidation Common Shares for every one post-consolidation Common Share which was effected on May 30, 2019.

Convertible Debentures means our convertible unsecured subordinated debentures.

Debenture Indenture means the indenture, as amended, between us and the Debenture Trustee governing the terms of the Convertible Debentures.

SEC means the United States Securities and Exchange Commission.

U.S. Loan Agreement means the financing agreement dated as of November 1, 2018 among us and certain private investment funds advised by JGB Capital Management, LP.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	gj	gigajoule
bbl/d	barrels per day	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	bcf	billion cubic feet
NGLs	natural gas liquids	Mcf/d	thousand cubic feet per day
		MMcf/d	million cubic feet per day
		MMbtu	million British Thermal Units

Other

ADR	means abandonment, decommissioning and reclamation
ASP	means alkaline surfactant polymer
BOE or boe	means barrel of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
Mmboe	million barrels of oil equivalent
Psi	pounds per square inch
WCS	Western Canadian Select
WTI	West Texas Intermediate
^{o}API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
$000s	thousands of dollars
U.S.	United States
USD	United States dollars

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	Metres	0.305
metres	Feet	3.281
miles	Kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.948
MMbtu	Gigajoules	1.0551

We have adopted the standard of 6 mcf: 1 bbl when converting natural gas to oil and 1 bbl: 6 mcf when converting oil to natural gas. **Boe's 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. In addition, 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.**

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into 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 may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negative thereof).

In addition, there are forward-looking statements in this Annual Information Form under the headings: *General Development of Our Business* with respect to the use of proceeds of the Replacement U.S. Loan Agreement; *Description of Our Business* relating to our business plan, focus and strategy, our acquisition and disposition plans, our future capital expenditures and sources of funding; our expectations with respect to the effect of the renegotiation or termination of contracts or subcontracts in 2020 and the continuation of us as a going concern; *Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information* as to our reserves, future net revenues from our reserves, anticipated after-tax value of such revenues, pricing and inflation and exchange rates, future development costs and the sources of funding of our future development costs, our reclamation and abandonment obligations and the sources of funding such obligations, and the development of our proved undeveloped reserves and probable undeveloped reserves; *Description of Our Business – Other Oil and Gas Information* as to our future development activities and the results therefrom, drilling inventory, land expiries, hedging policies, tax horizon, production estimates, our development plans, results and plans relating to our ASP project, and our reclamation and abandonment obligations; and *Dividends* with respect to our dividend policy.

This information involves 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 information. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices and differentials, escalation of operating and capital costs, regulatory approvals required in connection with our Little Bow ASP project, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future to allow investors to have a greater understanding of our business. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices and differentials; the continuation of us as a going concern; future capital expenditures levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that we disclaim, except as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contains forward-looking statements pertaining to the following:

- our business plan and strategy;
- the performance characteristics of our oil and natural gas properties;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes and tax laws.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of numerous known and unknown risks and uncertainties and other factors set forth below and elsewhere in this Annual Information Form, many of which are beyond our control. Such factors include, but are not limited to:

- variations in oil and natural gas prices and differentials;
- variations in interest rates and foreign exchange rates;
- uncertainties relating to the global economy and access to capital, stock market volatility, market valuations and increased borrowing costs;
- refinancing risk for existing debt and debt service costs;
- access to external sources of capital, borrowings and equity sales;
- risks associated with our hedging activities;
- geological, technical, drilling and processing problems;
- third party credit risk;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- government regulation and control and changes in governmental legislation;
- changes in income tax laws, royalty rates and other incentive programs;
- uncertainties associated with estimating oil and natural gas reserves;
- risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations;
- risks associated with the marketability of oil and natural gas;
- changes in climate change laws and other environmental regulations;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- competition in the oil and natural gas industry;
- depletion of our reserves;
- risks associated with large projects or expansion of our activities;
- risks associated with retention of key personnel;
- risks associated with securing and maintaining our properties;
- seasonality;
- risks associated with the timing of payment of dividends; and
- the other risks described under the heading *Risk Factors*.

In addition, statements relating to "reserves" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable law.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 1100, 112 – 4th Avenue S.W., Calgary, Alberta, T2P 0H3.

Drilling Locations

This Annual Information Form discloses drilling locations in three categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations. The following is a break down of the 32 drilling locations referred to in this Annual Information Form.

	Proved Undeveloped	Probable Undeveloped	Unbooked
Williston Basin	-	7	9
Bellshill Lake	5	-	3
Taber South	-	3	5
Total	5	10	17

Proved undeveloped locations and probable undeveloped locations are booked and derived from the McDaniel Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Oil and Gas Metrics

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

Non-GAAP Measures

This Annual Information Form contains the term "netback" which does not have a standardized meaning under generally accepted accounting principles in Canada and therefore may not be comparable with the calculation of similar measures by other companies. We use netback to analyze our financial and operating performance. Netback is not intended to represent operating profits nor should it be viewed as an alternative to net earnings or other measures of financial performance calculated in accordance with generally accepted accounting principles in Canada. In this Annual Information Form, netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

ZARGON OIL & GAS LTD.

General

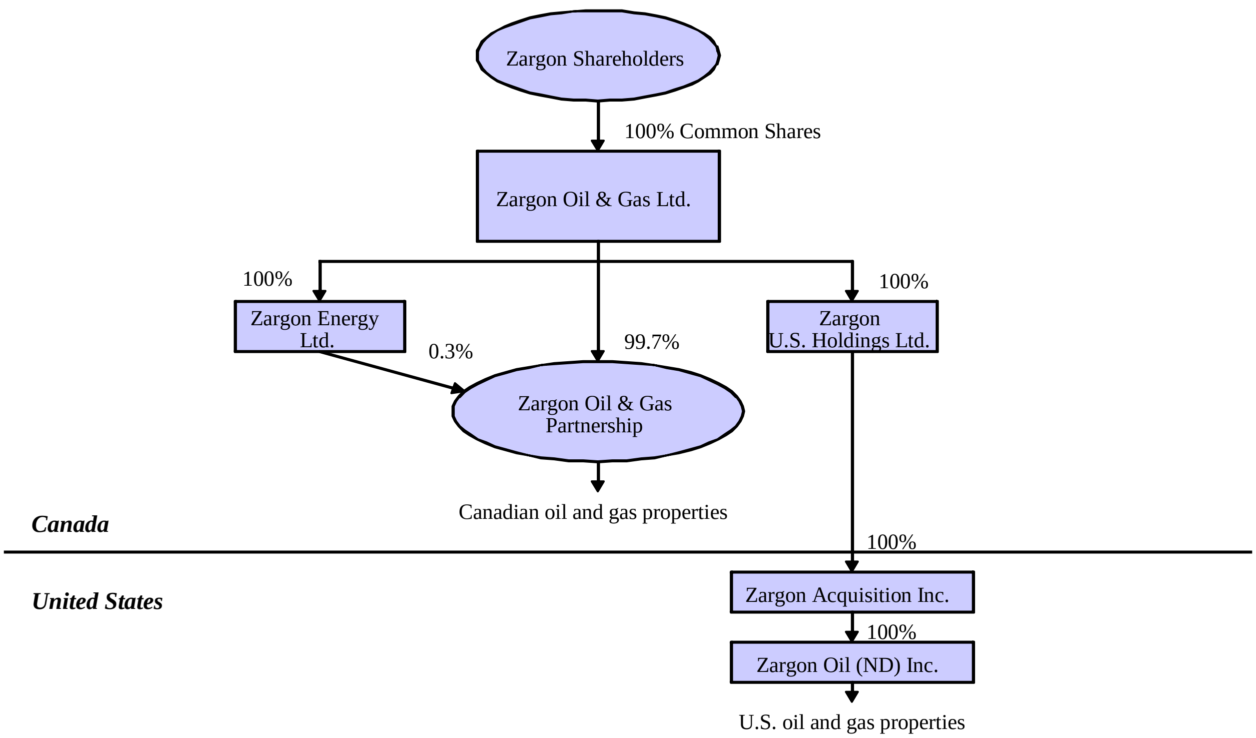
We were created on January 1, 2011 pursuant to the Arrangement.

On January 1, 2014, our wholly owned subsidiary, Ashton Oil & Gas Ltd., was amalgamated into us.

Our registered, head and principal office is located at Suite 1100, 112 – 4th Avenue S.W., Calgary, Alberta, T2P 0H3.

Our Organization Structure

The following diagram describes the inter-corporate relationships between us and our material subsidiaries and partnership.



Inter-Corporate Relationships

The following are the names and percentages of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnership either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Zargon Energy Ltd.	100%	Corporation	Alberta
Zargon Oil & Gas Partnership	100%	General Partnership	Alberta
Zargon U.S. Holdings Ltd.	100%	Corporation	Alberta
Zargon Acquisition Inc.	100%	Corporation	Wyoming
Zargon Oil (ND) Inc.	100%	Corporation	Delaware

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

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

Developments in 2017

On January 12, 2017, we announced that we had entered into hedges to fix the WTI price of oil on 650 bbl/d of oil production at an average of $71.50 in Canadian dollars for the period February to December 2017 bringing the total volumes hedged from February to December 2017 to 1,300 bbl/d at an average price of $69.24 Canadian.

On February 14, 2017, following an extraordinary meeting of the holders of our Convertible Debentures, we amended the terms of the Debenture Indenture and the Convertible Debentures to: (i) extend the maturity date of the Convertible Debentures from June 30, 2017 to December 31, 2019; (ii) increase the interest rate of the Convertible Debentures from 6.00% per annum to 8.00% per annum effective April 1, 2017; (iii) change the interest payment dates applicable to the Convertible Debentures under the Debenture Indenture from June 30, and December 31 to March 31, and September 30; (iv) reduce the conversion price in effect for each Common Share to be issued upon the conversion of the Convertible Debentures from $18.80 to $1.25; (v) amend the redemption provisions of the Convertible Debentures to provide holders with a right to require us to redeem up to $19 million aggregate principal amount of Convertible Debentures (or such other amount as determined by us) at a cash price determined by a "Dutch auction" process (the; and (vi) amend the redemption provisions to provide that (other than in connection with the right to require us to redeem up to $19 million aggregate principal amount of Convertible Debentures) the Convertible Debentures were not redeemable by us before January 1, 2019, and for the 12 months following January 1, 2019 and to provide that the Convertible Debentures could only be redeemed by us if the Current Market Price (as defined in the Debenture Indenture) of the Common Shares exceeds 125% of the reduced conversion price.

On February 27, 2017, we entered into a hedge to fix the differential between WTI and WCS at $19.50 Canadian dollars for the period April to December 2017.

On April 1, 2017, pursuant to the "Dutch" auction, we redeemed $15.56 million aggregate principal amount of the Convertible Debentures at tender prices ranging from $890 to $1,000 per $1,000 principal amount, for total cash consideration of $14.84 million, which is equivalent to an average cost of $954 per $1,000 principal amount of Convertible Debentures redeemed. After giving effect to the redemption, approximately $41.94 million aggregate principal amount of the Convertible Debentures remained outstanding. On the same day, the changes to the Convertible Debentures described above took effect and the Convertible Debentures not redeemed commenced trading on the Toronto Stock Exchange under the new symbol "ZAR.DB.A" at the open of markets on April 3, 2017.

On May 30, 2017, Mr. K. James Harrison retired from our Board and Mr. Kyle Kitagawa became our new Chairman.

During November and December 2017, we entered into WTI hedges to fix the price on 1,000 bbl/d of oil at an average price of $70.15 Canadian for the first quarter of 2018 and a WTI hedge to fix the price on 1,000 bbl/d of oil at a price of $70.50 Canadian for the second quarter of 2018.

Developments in 2018

On November 2, 2018 we entered into the U.S. Loan Agreement which provided us with approximately $3.5 million (USD) term debt. The loan is secured by all of our U.S. assets. The loan bears interest at 11% and principal repayments commence July 1, 2019 at $50,000 (USD) per month until September 1, 2019 and on October 1, 2019 principal repayments will be $75,000 (USD) per month until maturity at April 1, 2020 when the balance of the principal plus an original issue discount of $145,833 (USD) is payable.

Developments in 2019

On January 11, 2019, we settled all of the Debentures, including accrued and unpaid interest, for an aggregate of 428,878,324 Common Shares.

On January 16, 2019, we re-engaged Macquarie Capital Markets Canada Ltd. as our financial advisor to assist in seeking outcomes to maximize value for us and our stakeholders.

On February 21, 2019, we announced the appointment of Glenn Koach to our Board of Directors.

On May 30, 2019, we consolidated all of our issued and outstanding Common Shares on the basis of twenty pre-consolidation Common Shares for every one post-consolidation Common Share.

Significant Acquisitions

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

DESCRIPTION OF OUR BUSINESS

General

We are an Alberta based corporation engaged in the business of oil and natural gas exploration, exploitation, development, acquisition and production in Canada and the United States.

Our business plan is to deliver sustainable and profitable oil and natural gas property exploitation and production activities in the oil and natural gas industry. In recent years we have refocused our business on our long-life and low-decline conventional oil exploitation properties plus our Little Bow ASP tertiary oil project.

Capital Expenditures

Future capital expenditures on our properties will generally be of the type that are intended to maintain or improve production from our properties. We may finance capital expenditures from production revenues, the proceeds of the issue of additional Common Shares or other securities or from the proceeds of disposition of properties, borrowings, and farmouts or with working capital.

We may acquire additional properties and related tangible equipment and fund such acquisitions from production revenues, the net proceeds of any issue of additional Common Shares or other securities or from the proceeds of disposition of properties, or from borrowings, farmouts or with working capital. We may sell any of our interests in properties. In connection with the sale of any interests in our properties, we will determine whether the net proceeds of the sale should be reinvested in additional properties or capital expenditures, used to repay debt or distributed to our Shareholders.

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of oil and natural gas assets and in the marketing of oil and natural gas. Our competitors include resource companies which may have greater financial resources, staff and facilities than us. See *Industry Conditions* and *Risk Factors*.

Cyclical and Seasonal Impact of Industry

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

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2020 by the renegotiation or termination of contracts or subcontracts other than the repayment of our U.S. Loan Agreement. See *Material Reorganizations – Going Concern* and *Risk Factors – Risks Relating to Our Business and Operations*.

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against us, or any voluntary receivership, bankruptcy or similar proceeding by us within the three most recently completed financial years or proposed for us for our current financial year.

Material Reorganizations

There has been no material reorganization of us or any of our subsidiaries within the three most recently completed financial years or completed during or proposed for the current financial year.

Going Concern

Our December 31, 2019 audited financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that we will be able to realize our assets and discharge our liabilities in the normal course of business. For the year ended December 31, 2019, we had working capital of $1.56 million (defined as current assets less accounts payable), positive cash flows from operating activities of $2.22 million and generated a net earnings of $22.54 million (including a $27.03 million gain on the Convertible Debentures in the first quarter of 2019).

In an effort to mitigate these challenges, in November of 2018 we entered into the U.S. Loan Agreement which provided us with approximately $3.50 million (USD) term debt and in January of 2019 we settled all of the Convertible Debentures, including accrued and unpaid interest, for an aggregate of 428.88 million Common Shares.

Our debt matures on April 1, 2020, at which time the principal amount of $3.05 million (USD) will be due and payable. We are attempting to refinance the debt or extend the term of the debt with the existing lender. The outcome of these efforts is extremely uncertain, and in the event that the debt comes due without a refinancing or extension we do not anticipate having sufficient funds to pay the debt and the lender could declare an event of default and realize on their security, which consists of our U.S. assets. There is still ongoing material uncertainty that may cast significant doubt on our ability to continue as a going concern and therefore, we may be unable to realize our assets and discharge our liabilities in the normal course of business. The continuation of us as a going concern is dependent upon the occurrence of all or some of these future events: actual prices exceeding the current estimates in the coming six months, accessing additional capital, or other unforeseen events. See *General Development of Our Business – Developments in 2018, 2019* and *Risk Factors – Risks Relating to Our Business and Operations*.

Human Resources

At December 31, 2019, we employed 15 full-time employees and 12 consultants, including nine office and six field employees.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

This statement of reserves data and other oil and gas information set forth below is dated January 21, 2020. The effective date of the statement is December 31, 2019 and the preparation date of the statement is January 21, 2020. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix A and the Report on Reserves Data by McDaniel attached hereto as Appendix B.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2019 contained in the McDaniel Report. The reserves data summarizes our 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. 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 plus probable reserves and no attempt was made to evaluate possible reserves.

Our reserves are in Canada in the province of Alberta, and in the United States in North Dakota.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel's before income tax future net revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions: corporate income tax at the current legislated rate; annual general and administrative expenses at the current rate; interest expense at the current rate; tax pool deductions utilizing our existing estimated $204 million of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by McDaniel and any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

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 for all wells, pipelines and facilities, whether or not they have been attributed reserves. **Estimated values of future net revenues presented in the tables below do not represent the fair market value of the 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 our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein**. 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. For more information as to the risks involved, see *Risk Factors – Risks Relating to Our Business and Operations*.

Reserves Data (Forecast Prices and Costs)

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

CANADA

	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	738	635	2,372	2,210	2,649	2,480	52	44
Developed Non-Producing	72	67	149	142	354	326	12	9
Undeveloped	-	-	100	91	3	3	-	-
Total Proved	**810**	**702**	**2,621**	**2,443**	**3,006**	**2,809**	**64**	**53**
Probable	**441**	**382**	**869**	**796**	**1,059**	**960**	**20**	**17**
Total Proved Plus Probable	**1,251**	**1,084**	**3,490**	**3,239**	**4,065**	**3,769**	**84**	**70**

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	(20,264)	4,635	11,121	12,788	12,938
Developed Non-Producing	6,238	4,793	3,830	3,152	2,652
Undeveloped	2,403	1,797	1,357	1,030	780
Total Proved	**(11,623)**	**11,225**	**16,308**	**16,970**	**16,370**
Probable	**38,311**	**23,960**	**16,519**	**12,153**	**9,341**
Total Proved Plus Probable	**26,688**	**35,185**	**32,827**	**29,123**	**25,711**

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	(20,264)	4,635	11,121	12,788	12,938
Developed Non-Producing	6,238	4,793	3,830	3,152	2,652
Undeveloped	2,403	1,797	1,357	1,030	780
Total Proved	**(11,623)**	**11,225**	**16,308**	**16,970**	**16,370**
Probable	**38,311**	**23,960**	**16,519**	**12,153**	**9,341**
Total Proved Plus Probable	**26,688**	**35,185**	**32,827**	**29,123**	**25,711**

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

CANADA

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [(1)] BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil [(2)]	4,617	6.12
	Heavy Crude Oil [(2)]	32,095	13.14
	Conventional Natural Gas [(3)]	1,199	0.43
	Total Proved before ADR costs	37,911	
	ADR Costs [(4)]	(21,603)	
	Total	**16,308**	
Proved plus Probable	Light and Medium Crude Oil [(2)]	10,944	9.48
	Heavy Oil [(2)]	42,026	12.97
	Conventional Natural Gas [(3)]	1,601	0.42
	Total Proved plus Probable before ADR costs	54,571	
	ADR Costs [(4)]	(21,744)	
	Total	**32,827**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Includes solution gas and other by-products.
(3) Includes by-products, but excludes solution gas and by-products from oil wells.
(4) These are estimated abandonment, decommissioning and reclamation costs for all wells (existing, undrilled, suspended and uncompleted wells), pipelines and facilities whether or not they have been attributed reserves.

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

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	1,788	1,347	-	-	-	-	-	-
Developed Non-Producing	5	4	-	-	-	-	-	-
Undeveloped	194	147	-	-	-	-	-	-
Total Proved	**1,987**	**1,498**	-	-	-	-	-	-
Probable	**747**	**570**	-	-	-	-	-	-
Total Proved Plus Probable	**2,734**	**2,068**	-	-	-	-	-	-

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	23,488	20,697	16,845	13,964	11,905
Developed Non-Producing	(5)	(7)	(8)	(9)	(9)
Undeveloped	2,657	1,649	937	444	101
Total Proved	**26,140**	**22,339**	**17,774**	**14,399**	**11,997**
Probable	**21,780**	**11,215**	**6,654**	**4,207**	**2,709**
Total Proved Plus Probable	**47,920**	**33,554**	**24,428**	**18,606**	**14,706**

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	16,021	15,400	12,783	10,677	9,144
Developed Non-Producing	(4)	(5)	(6)	(7)	(7)
Undeveloped	1,990	1,231	695	324	65
Total Proved	**18,007**	**16,626**	**13,472**	**10,994**	**9,202**
Probable	**16,855**	**8,451**	**4,941**	**3,073**	**1,930**
Total Proved Plus Probable	**34,862**	**25,077**	**18,413**	**14,067**	**11,132**

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

UNITED STATES

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE (1) BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	19,508	13.02
	Heavy Crude Oil (2)	-	
	Conventional Natural Gas (3)	-	
	Total Proved before ADR costs	19,508	
	ADR Costs (4)	(1,734)	
	Total	**17,774**	
Proved plus Probable	Light and Medium Crude Oil (2)	26,183	12.66
	Heavy Oil (2)	-	
	Conventional Natural Gas (3)	-	
	Total Proved plus Probable before ADR costs	26,183	
	ADR Costs (4)	(1,755)	
	Total	**24,428**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Includes solution gas and other by-products.
(3) Includes by-products, but excludes solution gas and by-products from oil wells.
(4) These are estimated abandonment, decommissioning and reclamation costs for all wells (existing, undrilled, suspended and uncompleted wells), pipelines and facilities whether or not they have been attributed reserves.

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

AGGREGATE

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	2,526	1,982	2,372	2,210	2,649	2,480	52	44
Developed Non-Producing	77	71	149	142	354	326	12	9
Undeveloped	194	147	100	91	3	3	-	-
Total Proved	**2,797**	**2,200**	**2,621**	**2,443**	**3,006**	**2,809**	**64**	**53**
Probable	**1,188**	**952**	**869**	**796**	**1,059**	**960**	**20**	**17**
Total Proved Plus Probable	**3,985**	**3,152**	**3,490**	**3,239**	**4,065**	**3,769**	**84**	**70**

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	3,224	25,332	27,966	26,752	24,843
Developed Non-Producing	6,233	4,786	3,822	3,143	2,643
Undeveloped	5,060	3,446	2,294	1,474	881
Total Proved	**14,517**	**33,564**	**34,082**	**31,369**	**28,367**
Probable	**60,091**	**35,175**	**23,173**	**16,360**	**12,050**
Total Proved Plus Probable	**74,608**	**68,739**	**57,255**	**47,729**	**40,417**

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year)

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	(4,243)	20,035	23,904	23,465	22,082
Developed Non-Producing	6,234	4,788	3,824	3,145	2,645
Undeveloped	4,393	3,028	2,052	1,354	845
Total Proved	**6,384**	**27,851**	**29,780**	**27,964**	**25,572**
Probable	**55,166**	**32,411**	**21,460**	**15,226**	**11,271**
Total Proved Plus Probable	**61,550**	**60,262**	**51,240**	**43,190**	**36,843**

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

AGGREGATE

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [(1)] BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil [(2)]	24,125	10.71
	Heavy Crude Oil [(2)]	32,095	13.14
	Conventional Natural Gas [(3)]	1,199	0.43
	Total Proved before ADR costs	57,419	
	ADR Costs [(4)]	(23,337)	
	Total	**34,082**	
Proved plus Probable	Light and Medium Crude Oil [(2)]	37,127	11.52
	Heavy Oil [(2)]	42,026	12.97
	Conventional Natural Gas [(3)]	1,601	0.42
	Total Proved plus Probable before ADR costs	80,754	
	ADR Costs [(4)]	(23,499)	
	Total	**57,255**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Includes solution gas and other by-products.
(3) Includes by-products, but excludes solution gas and by-products from oil wells.
(4) These are estimated abandonment, decommissioning and reclamation costs for all wells (existing, undrilled, suspended and uncompleted wells), pipelines and facilities whether or not they have been attributed reserves.

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

($000s) RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS (1)	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves								
Canada	260,457	23,011	171,127	3,314	74,628	(11,623)	-	(11,623)
United States	163,187	40,221	78,506	4,040	14,280	26,140	8,133	18,007
Total	423,644	63,232	249,633	7,354	88,908	14,517	8,133	6,384
Proved Plus Probable Reserves								
Canada	371,516	34,267	226,735	8,607	75,219	26,688	-	26,688
United States	231,421	56,509	102,238	9,911	14,843	47,920	13,058	34,862
Total	602,937	90,776	328,973	18,518	90,062	74,608	13,058	61,550

Note:

(1) These are estimated abandonment, decommissioning and reclamation costs for all wells (existing, undrilled, suspended and uncompleted wells), pipelines and facilities whether or not they have been attributed reserves.

Definitions and Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook, NI 51-101 and CSA 51-324. A summary of certain of those definitions is set forth below.

   Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

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

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

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

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

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

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.

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

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

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (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.

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

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:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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.

Forecast Prices and Costs

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts ("**IQRE Average Forecast**") by McDaniel, GLJ Petroleum Consultants and Sproule Associates Limited, The IQRE Average Forecast is dated January 1, 2020. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

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

SUMMARY OF THREE CONSULTANT (MCDANIEL, GLJ AND SPROULE) AVERAGE PRICING AND INFLATION RATE ASSUMPTIONS AS OF JANUARY 1, 2020 FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Bow River Hardisty API ($Cdn/bbl)	Alberta Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/ MMBTU)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl) (3)	Inflation Rate(1) %/year	Exchange Rate(2) ($US/ $Cdn)
Forecast									
2020	61.00	72.64	58.43	51.23	70.29	2.04	42.00	-	0.760
2021	63.75	76.06	63.00	56.11	72.93	2.32	45.80	1.7	0.770
2022	66.18	78.35	64.99	57.72	74.73	2.62	49.00	2.0	0.785
2023	67.91	80.71	66.91	59.45	77.00	2.71	50.50	2.0	0.785
2024	69.48	82.64	68.65	61.09	78.87	2.81	48.30	2.0	0.785
2025	71.07	84.60	70.41	62.75	80.76	2.89	53.00	2.0	0.785
2026	72.68	86.57	72.20	64.43	82.67	2.96	54.30	2.0	0.785
2027	74.24	88.49	73.91	66.04	84.53	3.03	55.50	2.0	0.785
2028	75.73	90.31	75.53	67.55	86.29	3.09	56.70	2.0	0.785
2029	77.24	92.17	77.18	69.08	88.08	3.16	57.90	2.0	0.785
2030	78.79	94.01	78.72	70.46	89.84	3.23	59.00	2.0	0.785
2031	80.36	95.89	80.29	71.87	91.64	3.29	60.20	2.0	0.785
2032	81.97	97.81	81.90	73.31	93.47	3.36	61.40	2.0	0.785
2033	83.61	99.76	83.54	74.78	95.34	3.43	62.70	2.0	0.785
2024	85.28	101.76	85.21	76.27	97.24	3.49	63.90	2.0	0.785
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	2.0	0.785

Notes:

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rates used to generate the benchmark reference prices in this table.

(3) NGL mix calculated from McDaniel Report based on 45 percent propane, 35 percent butane and 20 percent natural gasoline of Edmonton propane, Edmonton butanes and Edmonton condensate and natural gasoline reference prices, respectively.

Weighted average historical prices realized by us (before the impact of financial risk management contracts) for the year ended December 31, 2019, were $0.72/Mcf for conventional natural gas, $61.61/bbl for light and medium crude oil, $38.77/bbl for natural gas liquids and $60.70/bbl for heavy crude oil.

Future Development Costs

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

CANADA

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2020	3,153	6,799
2021	145	1,708
2022	-	-
2023	-	84
2024	-	-
Thereafter	16	16
Total Undiscounted	3,314	8,607
Total Discounted at 10%	3,094	7,971

UNITED STATES

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2020	1,297	5,766
2021	1,410	2,812
2022	1,333	1,333
2023	-	-
2024	-	-
Thereafter	-	-
Total Undiscounted	4,040	9,911
Total Discounted at 10%	3,523	9,021

AGGREGATE

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2020	4,450	12,565
2021	1,555	4,520
2022	1,333	1,333
2023	-	84
2024	-	-
Thereafter	16	16
Total Undiscounted	7,354	18,518
Total Discounted at 10%	6,617	16,992

Notes:

(1) We fund the development costs of our reserves through a combination of internally generated cash flows from operating activities, debt and the issuance of Common Shares or other securities. Our capital spending in 2020 is expected to be less than the development costs deducted in the estimation of the future net revenue attributable to our reserves due to our restricted cash flows from operating activities and there is no certainty that sufficient 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 would have a negative impact on our future cash flows from operating activities and a reduction in our reserves. See *Risk Factors – Risks Relating to Our Business and Operations*.

(2) At this time, there are no expectations that the costs of funding would make development of a property uneconomic.

(3) The interest or other costs of external funding are not included in the reserves and future net revenue estimates. This 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 property uneconomic.

(4) Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property. Reasonable estimated future well abandonment costs were deducted in determining the aggregate future net revenue. No allowance was made, however, for reclamation of well sites not assigned reserves or the abandonment and reclamation of any facilities.

(5) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(6) The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliation of Changes in Reserves

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM CRUDE OIL			**HEAVY CRUDE OIL**			**CONVENTIONAL NATURAL GAS**		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2018	988	468	1,456	2,848	1,009	3,857	4,071	1,343	5,414
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	(14)	(20)	(34)	57	(140)	(83)	(499)	(280)	(779)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(34)	(7)	(41)	-	-	-	(17)	(4)	(21)
Production	(130)	-	(130)	(284)	-	(284)	(549)	-	(549)
December 31, 2019	**810**	**441**	**1,251**	**2,621**	**869**	**3,490**	**3,006**	**1,059**	**4,065**

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

UNITED STATES

FACTORS	LIGHT AND MEDIUM CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	HEAVY CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	CONVENTIONAL NATURAL GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2018	2,085	742	2,827	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	37	5	42	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(135)	-	(135)	-	-	-	-	-	-
December 31, 2019	**1,987**	**747**	**2,734**	-	-	-	-	-	-

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

AGGREGATE

FACTORS	LIGHT AND MEDIUM CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	HEAVY CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	CONVENTIONAL NATURAL GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2018	3,073	1,210	4,283	2,848	1,009	3,857	4,071	1,343	5,414
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	23	(15)	8	57	(140)	(83)	(499)	(280)	(779)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(34)	(7)	(41)	-	-	-	(17)	(4)	(21)
Production	(265)	-	(265)	(284)	-	(284)	(549)	-	(549)
December 31, 2019	**2,797**	**1,188**	**3,985**	**2,621**	**869**	**3,490**	**3,006**	**1,059**	**4,065**

The reduction in reserves was primarily due to the suspension of future tertiary recovery program based on lower future price forecasts and the shut-in of uneconomic properties.

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. In our practice, proved undeveloped reserves tend to be those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from our gathering systems. In addition, such reserves may relate to planned infill drilling locations. Probable undeveloped reserves may be reserves tested or indicated by analogy to be productive, infill drilling location and lands contiguous to production. In either case, the majority of undeveloped reserves are planned to be on stream within a two-year time frame. Undeveloped proved and probable reserves represent only about 12 percent of our proved and probable reserves.

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). For more information, see *Risk Factors – Risks Relating to Our Business and Operations*.

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbl)**		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**NGLs (Mbbl)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2017	-	254	-	100	-	3	-	-
2018	-	254	-	100	-	3	-	-
2019	-	194	-	100	-	3	-	-

A total of 294 Mbbl of oil, three MMcf of gas and no NGLs were assigned as proved undeveloped reserves in the McDaniel Report at December 31, 2019, representing six percent of our total proved reserves. In estimating future net revenue McDaniel reviewed our future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set out under *Future Development Costs* are consistent with our future development plans if future prices meet or exceed the McDaniel price forecast. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by recent drilling results and offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent in 2020, with carry over into 2021. Within the McDaniel Report, 77 percent of the capital is scheduled to be spent over the next two years. Our capital spending in 2020 and 2021 may be less than planned due to our restricted cash flows from operating activities and there is no certainty that sufficient funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report.

Probable Undeveloped Reserves

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

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2017	100	401	-	1,448	-	838	-	11
2018	142	543	-	100	-	33	-	1
2019	87	630	-	100	-	28	-	1

A total of 730 Mbbl of oil, 28 MMcf of gas and one Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2019, representing approximately 14 percent of our total probable reserves or 10 percent of our total proved plus probable reserves. The majority of the probable reserves assignment relates to properties which have proved producing reserves assigned. The bulk of the probable undeveloped reserves are assigned to projects which are actively underway or are contemplated in our forecasted capital program based on the McDaniel price forecast. Of the total future development costs assigned in the McDaniel Report for probable undeveloped reserves 100 percent are forecast to be spent in 2020 and 2021. Our capital spending in 2020 and 2021 may be less than planned due to our restricted cash flows from operating activities and there is no certainty that sufficient funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report.

Significant Factors or Uncertainties Affecting Reserves Data

Our reserves have been evaluated in accordance with NI 51-101 by McDaniel, an independent engineering firm, effective December 31, 2019. Our audit and reserves committee has reviewed the scope and methodology of McDaniel's evaluation; any significant new discoveries, additions, revisions and acquisitions, and reviewed the assumptions and consistency with prior years.

Our reserves are characterized by a high developed producing component. This reflects our core competencies of oil exploitation, increasing oil production and reserves from existing reservoirs. It is a technically complex business and each oil reservoir is treated differently depending on the interrelationships of the reservoir rock, fluids, pressures, wells and surface facilities. As circumstances change and additional data becomes available, our reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Changes in future commodity prices relative to the forecasts provided under *Pricing Assumptions* above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above our evaluated oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and gas producing company as described in our management's discussion and analysis relating to our 2019 annual audited consolidated financial statements under the heading *Risk Factors* and *Outlook*, which is incorporated herein by reference. See also *Risk Factors – Risks Relating to Our Business and Operations*.

Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. We budget for and recognize as a liability the estimated present value of the future decommissioning liabilities associated with our property, plant and equipment. Our overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flows from operating activities.

We estimate the costs to abandon and reclaim all of our producing and shut in wells, facilities, and pipelines. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

As at December 31, 2019, we had 609 net wells which we expect to incur abandonment and/or reclamation costs.

Estimated future abandonment and reclamation costs for all of our facilities, pipelines and wells including those without reserves have been taken into account by McDaniel and assigned at the cash-generating unit (“CGU”) level.

The total amount of abandonment and reclamation costs, net of estimated salvage values, from the McDaniel Report that we expect to incur are summarized in the following table.

Period	**Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)**	**Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)**
Total liability as at December 31, 2019	90,062	23,499
Anticipated to be paid in 2020	1,464	1,458
Anticipated to be paid in 2021	1,464	1,325
Anticipated to be paid in 2022	1,488	1,225

We have estimated the net present value of our total asset retirement obligations to be $61.35 million (which is calculated based on IAS 37 "*Provisions, Contingent Liabilities and Contingent Assets"* using a risk-free discount rate of 1.7% and an inflation rate of 1.5%) as at December 31, 2019 based on a total future liability of $63.92 million. In comparison, the net present value of our total asset retirement obligations is estimated to be $21.27 million as at December 31, 2019 using a discount rate of 10% and an inflation rate of 1.5%. These estimates of the net present value of our asset retirement obligations do not include abandonment costs for wells that have not yet been drilled. These future wells are included in the abandonment and reclamation costs, net of estimated salvage values, in the McDaniel Report.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2019. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2019. **Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

Our major properties are concentrated within Alberta in Canada and in North Dakota in the United States. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.

Alberta Plains

Our Alberta Plains core area holds 64 percent of our proved and probable oil and liquids reserves at year end 2019 and provided for 76 percent of our 2019 oil and liquids production, primarily from the Taber South, Little Bow, and Bellshill Lake properties.

The Bellshill Lake and Taber South properties are expected to require additional wells to optimally exploit. The McDaniel Report has booked five undeveloped Bellshill Lake vertical development locations and three horizontal locations in Taber South. Based on our geological, geophysical and reservoir engineering work, we have identified three additional undeveloped Bellshill Lake locations and five additional undeveloped Taber locations that have not been recognized in the McDaniel Report.

Our largest and most important property in this core area is Little Bow with its tertiary oil recovery opportunities plus a number of waterflood and production optimization projects. Over the last few years, we have assembled assets at Little Bow through a number of property and corporate acquisitions, which also consolidated our position in the ASP project. The Little Bow ASP tertiary oil recovery project entails the injection of chemicals in a dilute water solution into a partially depleted reservoir to recover incremental oil reserves.

In 2012, we received Alberta Energy Regulator approval and substantially completed the detailed engineering and the procurement of long-lead-time equipment for the Little Bow Upper Mannville I and P pool ASP project. During 2013, substantially all of the field construction was completed and final project commissioning commenced in the first quarter of 2014. The McDaniel Report has assigned 1.59 MMbbl of proved and probable oil and liquids reserves to the Little Bow ASP (Phase 1 and 2) project.

In March 2014, we commenced the injection of large volumes of dilute chemical solution into the partially depleted Little Bow Mannville I pool to recover incremental oil reserves. At December 31, 2019 a total of 7.0 million barrels of ASP solution has been injected into the first phase of the project. This injection volume represents approximately three quarters of target ASP volume. Due to low commodity pricing, full ASP injection was suspended in March 2016. Since then approximately 13.3 million barrels of polymer solution has been injected. A polymer solution is utilized to maintain the integrity of oil banks in anticipation of return to full ASP injection when financial conditions improve sufficiently.

In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the *Enhanced Oil Recovery Royalty Regulations* for the Little Bow ASP Project. With this approval, wells within the Little Bow phase 1 scheme area receive a five percent Alberta Crown oil royalty rate for a period of up to 10 years. The Alberta Modernized Royalty Framework released on January 29, 2016 does not directly affect the prior approvals under the existing Enhanced Oil Recovery Program. The Government of Alberta has committed to developing cost allowance programs for enhanced oil recovery schemes initiated after January 1, 2017. See *Industry Conditions – Royalties and Incentives – Alberta – Alberta Enhanced Oil Recovery Program*.

In March 2016, we suspended the alkali and surfactant injections into the Little Bow ASP Project in an effort to conserve funds. In the third quarter of 2016, we modified the ASP project's depletion strategy by shutting in higher water cut producers in under treated areas in order to reduce the polymer costs required to treat the re-injected water volumes. This strategy will maintain and produce the oil banks that have already been formed in the reservoir while preserving our ability to re-initiate the alkaline surfactant injections in the under treated areas, once higher oil prices and improved financial conditions permit.

Williston Basin

We have a long and profitable history in our Williston Basin core area, which encompassed certain assets in Southeast Saskatchewan that were sold in 2016, and three counties of North Dakota. Our remaining assets in the Williston Basin located in North Dakota hold 34 percent of our proved and probable oil and liquids reserves.

Based on our geophysical, geological and reservoir engineering work, we have identified 16 undeveloped Mississippian locations in the Williston Basin of which seven locations have been recognized in the McDaniel Report.

These locations are characterized by lower permeability reservoirs that are generally partially pressure supported by either weak aquifers or, in some cases, by mature waterfloods, and production from these locations will be characterized by relatively low initial rates, moderately high water cuts, and shallow production declines. In recent years, we have allocated most of our capital budget to the Little Bow ASP project, and virtually no drilling capital has been directed to the drainage locations at the North Dakota, properties.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2019.

	Oil Wells (1) (2)				Natural Gas Wells (2)			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	171.0	154.6	196.0	171.2	67.0	30.0	135.0	76.3
Saskatchewan	-	-	7.0	3.7	-	-	104.0	48.9
United States								
North Dakota	78.0	76.6	15.0	14.5	-	-	-	-
Total	249.0	231.2	218.0	189.4	67.0	30.0	239.0	125.2

Notes:

(1) Includes 82.0 gross and 80.7 net service wells such as water source, water injection and disposal wells.
(2) Excludes 49.0 gross and 32.9 net wells of non-producing undefined wells.
(3) Well counts are based on wellbores.
(4) We have no offshore wellbores.

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2019.

	Undeveloped Acres (1)	
(thousand acres)	Gross	Net
Alberta	59	25
British Columbia	-	-
Saskatchewan	5	2
United States	2	2
Total	66	29

Notes:

(1) None of our undeveloped lands have reserves attributed to them.
(2) Rights to explore, develop and exploit nil net acres of our undeveloped land holdings in Canada and 240 net acres of our undeveloped land holdings in the United States are scheduled to expire by December 31, 2019.
(3) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

Our business model focuses on sustainable low decline production with little capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes all of which are beyond our control. See *Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs* and *Risk Factors*.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates, electricity rates and interest rates in the normal course of our operations. A variety of derivative instruments are used to reduce exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially strong counterparties. For information in relation to our marketing arrangements, see *Marketing Arrangements*.

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2019 see Note 25 to our 2019 annual audited consolidated financial statements, which is incorporated herein by reference.

Tax Horizon

We did not pay Canadian income taxes in 2019 and have incurred $0.19 million in United States income taxes in 2019. Based on the current forward commodity strip, we do not expect to pay cash taxes in Canada before 2035.

Costs Incurred

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

($ million)	**Canada**	**United States**	**Total**
Property Acquisition/(Disposition) Costs:			
Proved Properties (1)	-	-	-
Unproved Properties	0.95	0.02	0.97
Corporate Acquisitions	0.02	0.01	0.03
Development Costs (2)	1.92	0.20	2.12
Exploration Costs (3)	0.20	0.08	0.28
Total	3.09	0.31	3.40

Notes:

(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2019 exploration wells drilled.

Exploration and Development Activities

We did not participate in any exploratory or development wells during the year ended December 31, 2019. For more details regarding our most important current exploration and development opportunities for 2020 see, *Other Oil and Gas Information – Oil and Gas Properties*.

Production Estimates

The following table sets out the volumes of 2020 gross production estimated in the McDaniel Report for the year ended December 31, 2019, which is reflected in the estimate of future net revenue disclosed in the tables contained under *Disclosure of Reserves Data and Other Oil and Natural Gas Information*.

CANADA	**Light and Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Heavy Crude Oil**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	338	1,495	25	788	1,400
Total Probable	37	21	1	38	80

CANADA	Light and Medium Crude Oil	Conventional Natural Gas	Natural Gas Liquids	Heavy Crude Oil	BOE
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved Plus Probable	375	1,516	26	826	1,480

UNITED STATES	Light and Medium Crude Oil	Conventional Natural Gas	Natural Gas Liquids	Heavy Crude Oil	BOE
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	377	-	-	-	377
Total Probable	77	-	-	-	77
Total Proved Plus Probable	454	-	-	-	454

Production History and Prices Received

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production expenses and resulting netbacks for the periods indicated.

CANADA

	Quarter Ended			
	2019			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	1,368	1,357	1,507	1,391
Light and Medium Crude Oil (bbl/d)	338	346	366	358
Heavy Crude Oil (bbl/d)	797	761	767	811
Natural Gas Liquids (bbl/d)	21	19	29	24
Combined (boe/d)	1,384	1,352	1,413	1,424
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	(0.03)	(1.55)	(1.02)	(0.26)
Light and Medium Crude Oil ($/bbl)	58.00	67.76	64.09	61.82
Heavy Crude Oil ($/bbl)	55.22	59.78	69.15	59.02
Natural Gas Liquids ($/bbl)	43.45	39.57	44.69	26.49
Combined ($/boe)	46.59	49.99	53.96	49.32
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	(0.11)	(0.10)	(0.03)	(0.07)
Light and Medium Crude Oil ($/bbl)	9.46	11.08	10.48	6.93
Heavy Crude Oil ($/bbl)	3.06	3.84	4.33	2.43
Natural Gas Liquids ($/bbl)	15.76	16.05	17.97	12.76
Combined ($/boe)	4.21	5.12	5.40	3.26
Production Costs:				
Conventional Natural Gas ($/Mcf)	5.10	7.13	5.51	7.32
Light and Medium Crude Oil ($/bbl)	39.72	38.01	34.07	39.11
Heavy Crude Oil ($/bbl)	28.99	27.48	29.19	29.74
Natural Gas Liquids ($/bbl)	22.81	18.19	18.86	13.35
Combined ($/boe)	31.78	32.61	30.93	34.13
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	(5.03)	(8.58)	(6.50)	(7.51)
Light and Medium Crude Oil ($/bbl)	8.82	18.67	19.54	15.78
Heavy Crude Oil ($/bbl)	23.17	28.46	35.63	26.85

	Quarter Ended			
	2019			
	Dec. 31	Sept. 30	June 30	Mar. 31
Natural Gas Liquids ($/bbl)	4.88	5.33	7.86	0.38
Combined ($/boe)	10.60	12.26	17.63	11.93

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses. See *Notice to Reader – Non-GAAP Measures*.

UNITED STATES

	Quarter Ended			
	2019			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d)	362	363	376	384
Heavy Crude Oil (bbl/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Combined (boe/d)	362	363	376	384
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	59.55	59.14	65.22	57.42
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	59.55	59.14	65.22	57.42
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	14.73	14.62	16.49	14.25
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	14.73	14.62	16.49	14.25
Production Costs:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	22.60	20.66	20.70	21.50
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	22.60	20.66	20.70	21.50
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	22.22	23.86	28.03	21.67
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	22.22	23.86	28.03	21.67

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses. See *Notice to Reader – Non-GAAP Measures*.

AGGREGATE

	Quarter Ended 2019 Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	1,368	1,357	1,507	1,391
Light and Medium Crude Oil (bbl/d)	700	709	743	741
Heavy Crude Oil (bbl/d)	797	761	767	811
Natural Gas Liquids (bbl/d)	21	19	29	24
Combined (boe/d)	1,746	1,715	1,790	1,808
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	(0.03)	(1.55)	(1.02)	(0.26)
Light and Medium Crude Oil ($/bbl)	58.80	63.35	64.66	59.54
Heavy Crude Oil ($/bbl)	55.22	59.78	69.15	59.02
Natural Gas Liquids ($/bbl)	43.45	39.57	44.69	26.49
Combined ($/boe)	49.28	51.93	56.33	51.04
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	(0.11)	(0.10)	(0.03)	(0.07)
Light and Medium Crude Oil ($/bbl)	12.19	12.89	13.53	10.72
Heavy Crude Oil ($/bbl)	3.06	3.84	4.33	2.43
Natural Gas Liquids ($/bbl)	15.76	16.05	17.97	12.76
Combined ($/boe)	6.39	7.13	7.73	5.60
Production Costs:				
Conventional Natural Gas ($/Mcf)	5.10	7.13	5.51	7.32
Light and Medium Crude Oil ($/bbl)	30.87	29.13	27.29	30.00
Heavy Crude Oil ($/bbl)	28.99	27.48	29.19	29.74
Natural Gas Liquids ($/bbl)	22.81	18.19	18.86	13.35
Combined ($/boe)	29.88	30.08	28.78	31.45
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	(5.03)	(8.58)	(6.50)	(7.51)
Light and Medium Crude Oil ($/bbl)	15.74	21.33	23.84	18.83
Heavy Crude Oil ($/bbl)	23.17	28.46	35.63	26.85
Natural Gas Liquids ($/bbl)	4.88	5.33	7.86	0.38
Combined ($/boe)	13.01	14.72	19.82	14.00

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses. See *Notice to Reader – Non-GAAP Measures*.

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

	Conventional Natural Gas (Mcf/d)	Light and Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Alberta Plains North	505	348	1	15	447
Alberta Plains South	901	4	783	8	946
Williston Basin	-	371	-	-	371
Total	1,405	723	784	23	1,764

Marketing Arrangements

Natural Gas

Most of our natural gas production was sold by spot sale contracts and Alberta index prices were received. In order to control and manage credit risk and ensure competitive bids, we engage with a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $1.59 per Mcf in 2019 compared to $1.43 per Mcf in 2018.

Oil and Natural Gas Liquids

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In general, we market our oil production with various purchasers under one month renewable contracts and receive posted reference prices with adjustments for quality and transportation. In 2019, our average realized oil and liquids price (after realized risk management gains/losses) was $58.68 per bbl compared to $50.20 per bbl in 2018.

Risk Management Activities

Our commodity price risk management policy, which is approved by the Board of Directors, allows for the sale of up to a certain percent of our estimated before royalty production volumes for each commodity for up to a 30 month period. For details of our risk management activities in 2019 see our management's discussion and analysis relating to our 2019 annual audited consolidated financial statements under the heading *Risk Management Activities*, which is incorporated herein by reference.

Acquisitions and Dispositions

We did not complete any material acquisitions or dispositions in the last twelve months.

Social and Environmental Policy

We approach social responsibility and sustainable development by seeking a balance among economic, environmental and social issues while maintaining growth. We strive to find solutions to these issues that do not compromise the needs of future generations and place a high priority on preserving the quality of the environment, protecting the health and safety of our employees, contractors and the public in the communities in which we operate. Additionally, we actively participate in industry recognized programs that support our sustainable mindset.

We have an environmental policy in place as part of our commitment to protecting the environment while conducting our operations.

Our environmental policy states that:

- Operating in an environmentally responsible manner is key to insuring our continued growth and the industry.

- Sound environmental management is an integral component of a good business plan. Environmental stewardship reduces costs and corporate liability. It enhances shareholder value, boosts employee morale and enhances our image in the eyes of regulators and the public.

- Managing our environmental responsibilities is a team effort requiring the commitment of management, employees and contractors.

- Preventing environmental damage is cheaper than repairing damage.

- An effective environmental program helps operations staff to understand and comply with environmental laws and regulations and to minimize the costs and liabilities associated with environmental damage. It helps meet the concerns of stakeholders that environmental issues are being managed properly and will provide a due-diligence defence in the event of an environmental incident.

Our management also monitors developments related to climate change and other environmental laws and regulations.

We are not currently impacted by proposed environmental laws and regulations relating to the control of greenhouse gases (see *Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*) as none of our facilities qualify and currently, no facility production qualifies under the criteria described in the Updated Action Plan (as defined therein). We will continue to monitor the regulatory developments and any impact that they may have on our future compliance costs.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2019, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, and gathering systems and processing facilities totaled $2.78 million. See *Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs* for further information

OUR CAPITAL STRUCTURE

Share Capital

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares without nominal or par value issuable in series (the "**Preferred Shares**"). The following is a summary of the rights, privileges, restrictions and conditions which attach to our securities. The inclusion of Preferred Shares in our authorized share capital is intended to provide us with the flexibility to raise a limited amount of future capital in the form of preferred shares. At the present time, our management is not aware of any financing structures for oil and gas companies that involve the issuance of preferred shares. The Preferred Shares will not be utilized as a defence to any take-over bid.

Common Shares

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

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

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

Preferred Shares

The Preferred Shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, our Board of Directors will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for our securities or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than Preferred Shares or payment in respect of capital on any shares in our capital or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) our Board of Directors may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together.

Debt

In 2016, we repaid our bank indebtedness and our Credit Agreement was terminated and has not been replaced.

On November 2, 2018 we entered into the U.S. Loan Agreement which provided us with approximately $3.5 million (USD) term debt. The loan is secured by all of our U.S. assets. The loan bears interest at 11% and principal repayments commenced July 1, 2019 at $50,000 (USD) per month until September 1, 2019 and on October 1, 2019 principal repayments changed to $75,000 (USD) per month until maturity at April 1, 2020 when the balance of the principal plus an original issue discount of $145,833 (USD) is payable. For more information, see *General Development of Our Business* and *Risk Factors – Risks Relating to Our Business and Operations*.

DIRECTORS AND OFFICERS

Directors

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our directors is as follows:

Name and Municipality of Residence	Director Since	Principal Occupation
Craig H. Hansen Calgary, Alberta	1992	Our President & Chief Executive Officer since 1993. Mr. Hansen is also a Governor of the Canadian Association of Petroleum Producers.
Kyle D. Kitagawa (1) (3) Calgary, Alberta	2001	Mr. Kitagawa is our Chairman. He brings over 25 years of experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of CES Energy Solutions Corp.
Glenn S. Koach Los Angeles, California	2019	Mr. Koach is Co-Founder/Portfolio Manager of Concise an SEC-registered investment adviser with currently over $340 million U.S. in assets under management that specializes in short duration, under-followed high yield bonds. Mr. Koach holds a Bachelor of Science in Economics with a major in Finance and Accounting from the Wharton School of Business at the University of Pennsylvania.

Name and Municipality of Residence	Director Since	Principal Occupation
Geoffrey C. Merritt (1) (3) Calgary, Alberta	2009	Mr. Merritt has been an independent businessman since April, 2009. Mr. Merritt was the founder of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by us in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy Corporation, a public oil and gas company. Prior to 1998, Mr. Merritt was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt currently sits on the board of Perpetual Energy Inc.
Jim Peplinski (2) (3) Calgary, Alberta	1997	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc., a commercial vehicle lessor. Mr. Peplinski is also the VP Business Development of the Calgary Flames Hockey Club as well as an investor in real estate and oil and gas.
Ron Wigham (1) (2) (3) Calgary, Alberta	2015	Mr. Wigham is an independent businessman and a director of Spur Petroleum Ltd. and Tourmaline Oil Corp. He retired in 2014 as Vice-Chairman of Peters & Co. Limited.
Grant A. Zawalsky (2) Calgary, Alberta	2000	Mr. Zawalsky is the Managing Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors) where he has been a partner since 1994. Mr. Zawalsky holds a B.Comm and LL.B. from the University of Alberta and is a member of the Law Society of Alberta. Mr. Zawalsky currently sits on the board of directors of a number of private and public companies, including NuVista Energy Ltd., PrairieSky Royalty Ltd. and Whitecap Resources Inc., and is Corporate Secretary of ARC Resources Ltd. and Bonavista Energy Corporation. Mr. Zawalsky is also a Governor of the Calgary Petroleum Club.

Notes:

(1) Member of our audit and reserves committee.
(2) Member of our governance and compensation committee.
(3) Member of our special committee of the board.
(4) We do not have an executive committee.
(5) Directors hold office until the next annual meeting of Shareholders or until their successors are duly elected or appointed.

Officers

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our officers (other than Mr. Hansen) is as follows:

Name and Municipality of Residence	Officer Since	Office
Randolph J. Doetzel Calgary, Alberta	2011	Vice President, Operations since June, 2011; prior thereto, our Production Manager, Williston Basin since January, 2009. Prior thereto, he held various executive, management and engineering positions at Cobalt Energy Ltd., Harvest Operations Corp., Apache Canada Ltd., and Samson Canada Ltd.

Name and Municipality of Residence	Officer Since	Office
Christopher M. Hustad Calgary, Alberta	2013	Vice President, Development since November, 2016; prior thereto, our Vice President, Alberta Plains South since February, 2013. Prior thereto, Manager Exploitation, Alberta Plains South since August, 2008. Prior thereto, various management and engineering positions at Talisman Energy Inc.
William T. Cromb Calgary, Alberta	2016	Chief Financial Officer since August 8, 2018; prior thereto, our Interim Chief Financial Officer since November 15, 2016. Prior thereto, he held financial positions with Provident Energy Trust, Beau Canada Exploration, North West Upgrading and Canterra Energy.

As at March 17, 2020, our directors and officers, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,104,898 Common Shares or approximately 4.8 percent of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially our control is, as of the date of this Annual Information Form, or has been, within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Zawalsky, who was a former director of Endurance Energy Ltd. (a private oil and gas company) which filed for creditor protection under the *Companies Creditors' Agreement Act* on May 30, 2016. Mr. Zawalsky resigned as a director of Endurance Energy Ltd. on November 1, 2016.

None of our directors or executive officers (nor any personal holding company of any such persons), or shareholder holding a sufficient number of our securities to materially affect the control of us has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

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

Conflicts of Interest

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

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

AUDIT AND RESERVES COMMITTEE INFORMATION

Audit and Reserves Committee Mandate and Terms of Reference

The Mandate of our audit and reserves committee is attached hereto as Schedule "C". The members of our audit and reserves committee are Ron Wigham, Kyle D. Kitagawa and Geoffrey C. Merritt.

Composition of the Audit and Reserves Committee

The members of our audit and reserves committee are independent (in accordance with National Instrument 52-110 – Audit Committees) and are financially literate.

Relevant Education and Experience

Name	Relevant Education and Experience
Ron Wigham (Audit and Reserves Committee Chairman)	Mr. Wigham is an independent businessman and a director of Spur Petroleum Ltd. and Tourmaline Oil Corp. He retired in 2014 as Vice-Chairman of Peters & Co. Limited. Mr. Wigham received a B.A. Finance in 1978 from the Honors College, University of Oregon and LLB from the University of Victoria in 1981.
Kyle D. Kitagawa	Mr. Kitagawa brings over 25 years of experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of CES Energy Solutions Corp. Mr. Kitagawa holds a Master of Business Administration degree from Queen's University, a Bachelor of Commerce from the University of Calgary and is a Chartered Professional Accountant.

Name	Relevant Education and Experience
Geoffrey C. Merritt	Mr. Merritt has over 30 years of experience in the upstream oil and gas sector. In 2003, he founded Masters Energy Inc., a public exploration and production company, which was acquired by Zargon in April 2009. From 1998 to 2003, Mr. Merritt was the President and Chief Executive Officer of Sunfire Energy. Prior to 1998, he was the Vice President and General Manager of the oil and gas division of Pembina Corporation. He currently sits on the board of Perpetual Energy Inc. Mr. Merritt received a Bachelor of Science in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Pre Approval Policies and Procedures

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

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditors, including expenses, in each of the last two fiscal years for audit services were $133,800 in 2019 and $133,800 in 2018.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditors, including expenses for tax compliance, tax advice and tax planning were $33,049 in 2019 and $64,437 in 2018.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors other than services reported above were nil in 2019 and $4,349 in 2018.

DIVIDENDS

We previously made monthly dividend payments to our Shareholders on the 15th day of each month or the first business day following the 15th day. The record date for any dividend was the last business day of the month preceding the dividend date or such other date as may be determined by our Board of Directors. All of these were designated as "eligible dividends" for Canadian income tax purposes.

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice.

We may reinstate dividend payments in the future. Actual future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including 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 the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Our Board of

Directors cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See *Risk Factors*.

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. Our ability to make cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including the solvency tests in the *Business Corporations Act* (Alberta)

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and posted for trading on the TSX under the trading symbol "ZAR". The Common Shares commenced trading on the TSX on January 7, 2011 following completion of the Arrangement. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Common Shares, as reported by the TSX for the periods indicated. The trading prices and volumes presented have been adjusted to give effect to the Consolidation.

Period	High	Low	Volume
2019			
January	0.900	0.600	608,410
February	0.900	0.600	500,214
March	0.900	0.600	436,633
April	1.000	0.600	646,637
May	1.000	0.500	787,150
June	0.480	0.325	1,305,902
July	0.380	0.340	765,056
August	0.400	0.330	797,610
September	0.420	0.320	780,242
October	0.360	0.230	398,165
November	0.250	0.130	1,293,608
December	0.240	0.160	678,793
2020			
January	0.230	0.180	238,397
February	0.180	0.095	1,037,694
March (1 – 17)	0.125	0.050	2,018,158

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect our operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, we are unable to predict what additional laws, regulations or amendments governments may enact in the future.

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

Pricing and Marketing in Canada

Crude Oil

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

Natural Gas

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

Natural Gas Liquids

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

Exports from Canada

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

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

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

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

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

Transportation Constraints and Market Access

Pipelines

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

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

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

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

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

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

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

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

Marine Tankers

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

Crude Oil and Bitumen by Rail

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

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

Natural Gas

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

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

2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

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

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

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being revised and finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

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

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

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

Curtailment

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

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

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

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

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

We are subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

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

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

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

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

Other Trade Agreements

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

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

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

Land Tenure

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

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

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. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the province of 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. We do not have operations on Indian reserve lands.

Royalties and Incentives

General

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

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

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

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

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

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

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

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

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

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

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

Alberta Enhanced Hydrocarbon Recovery Program

The Alberta government continues to encourage the use of enhanced oil recovery methods to promote incremental production and generate additional royalties and other benefits to Albertans. Enhanced hydrocarbon recovery methods use fluid injection such as chemicals (which includes ASP projects), hydrocarbons, CO2 or nitrogen allowing additional recovery. To promote these recovery techniques, the Enhanced Hydrocarbon Recovery Program was implemented as of January 1, 2017 replacing its predecessor, the Enhanced Oil Recovery Program. Under the program, after receiving approval from the Alberta Energy Regulator, the royalty rate for crude oil, natural gas, and natural gas liquids is set at a flat five percent for a period of up to 90 months. The duration of the fixed five percent royalty rate is dependent on the recovery methods used and the estimated additional amount of hydrocarbons that can be recovered using enhanced recovery methods. The Enhanced Hydrocarbon Recovery Program applies to applications made to the Alberta Energy Regulator on or after October 23, 2016. In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the Enhanced Oil Recovery Royalty Regulations for the Little Bow ASP Project. Approved applications made under the Enhanced Oil Recovery Program will continue to be effective until their benefit period ends or until the Enhanced Oil Recovery Program terminates on December 31, 2026. After two years, the approaches for determining the royalty benefit periods for the Enhanced Hydrocarbon

Recovery Program will be reviewed, and possibly revised, to better align with the Modernized Royalty Framework's cost allowance approach.

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

General

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

Federal

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

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

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. The case is expected to be heard in the fall of 2020.

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

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

Liability Management Rating Program

The AER administers the licensee *Liability Management Rating Program* (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

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

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including us, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

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

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

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

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets. We are 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 future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on our operations and cash flows from operating activities.

Federal

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

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the *Pan-Canadian Framework on Clean Growth and Climate Change* (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

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

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

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity. Finally, the federal government has also enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

Alberta

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

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The *Carbon Competitiveness Incentives Regime* ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to

$30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

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

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO_2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Accountability and Transparency

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

RISK FACTORS

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in the market price of the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment.

You should carefully consider the following risk factors, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading *Certain Risks for United States and Other Non-Resident Shareholders*.

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

Risks Relating to Our Business and Operations

Our operating performance, capital requirements and ability to raise capital cast doubt on our ability to continue to operate as a going concern

Our December 31, 2019 audited financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that we will be able to realize our assets and discharge our liabilities in the normal course of business. For the year ended December 31, 2019, we had working capital of $1.56 million (defined as current assets less accounts payable), positive cash flows from operating activities of $2.22 million and generated a net earnings of $22.54 million (including a $27.03 million gain on the Convertible Debentures in the first quarter of 2019).

In an effort to mitigate these challenges, in November of 2018 we entered into the U.S. Loan Agreement which provided us with approximately $3.50 million (USD) term debt and in January of 2019 we settled all of the Convertible Debentures, including accrued and unpaid interest, for an aggregate of 428.88 million Common Shares.

Our debt matures on April 1, 2020, at which time the principal amount of $3.05 million (USD) will be due and payable. We are attempting to refinance the debt or extend the term of the debt with the existing lender. The outcome of these efforts is extremely uncertain, and in the event that the debt comes due without a refinancing or extension we do not anticipate having sufficient funds to pay the debt and the lender could declare an event of default and realize on their security, which consists of our U.S. assets. There is still ongoing material uncertainty that may cast significant doubt on our ability to continue as a going concern and therefore, we may be unable to realize our assets and discharge our liabilities in the normal course of business. The continuation of us as a going concern is dependent upon the occurrence of all or some of these future events: actual prices exceeding the current estimates in the coming six months, accessing additional capital, or other unforeseen events.

We may require further financing in order to proceed with our operations and to fund our ongoing corporate and administrative activities.

There is material uncertainty related to future events that may cast substantial doubt on our ability to continue as a going concern and therefore, we may be unable to realize its assets and discharge our liabilities in the normal course of business. If the going concern assumption is not appropriate, adjustments may be necessary to the carrying amounts and classification of our assets and liabilities. Our 2019 audited financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

Macquarie Capital Markets Canada Ltd. is currently engaged as our exclusive financial advisor to evaluate strategic alternatives available to us which may include a sale of us or a portion of our assets, a restructuring of our current capital structure, the addition of capital to further develop the potential of the assets, a merger, a farm-in or joint venture, or other such options as may be determined by our Board of Directors to be in the best interests of us and our stakeholders. If we are unable to successfully finance our current and future operations, we may not be able to realize our assets and discharge our liabilities in the normal course of operations and could eventually result in, among other things, our default under Replacement U.S. Loan Agreement.

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition is dependent on the prices received for our oil and natural gas production. 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**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-hydrocarbon sentiment, have caused significant volatility in commodity prices. These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry.

These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between WCS crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada.

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19 (coronavirus), may adversely affect us by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing its 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 its workforce, rendering employees unable to work or travel.

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 natural 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 natural 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. If these conditions persist, our cash flow may not be sufficient to continue to fund its operations and to satisfy our obligations when due, and our ability to continue as a going concern and discharge our obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to us or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge our obligations and continue as a going concern.

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us, including:

- deliverability uncertainties related to the our reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. 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.
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. 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.

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.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. 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.

These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax and royalty changes.

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 uncertainty and reduced confidence in the oil and gas industry in western Canada.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

The economics of producing from some wells may change as a result of lower commodity prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. Volatile oil and natural gas prices also 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.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

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 our balance sheet and the recognition of an impairment charge in our income statement.

If oil and natural gas prices remain at their current levels or decrease further, our estimates of total reserves and present values thereof may be reduced.

Our reserves as at December 31, 2019 are estimated using forecast pricing escalating prices as set forth under *Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Forecast Prices and Costs*. These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels or drop further our reserves may be reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. Our capital spending in 2018 may be less than the development costs deducted in the estimation of the future net revenue attributable to our reserves due to our restricted cash flow. As a result, we may not be able to fund the future development capital necessary to develop our reserves and thereby replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis.

The performance of the Little Bow ASP project will have a material impact on us

The Little Bow ASP project is one of our key assets. The performance of this asset will have a material impact on our financial performance over the coming years. Risk factors associated with our ASP project include the following, without limitation:

Production Risks

There is a risk that production and reserves relating to the existing scope of the Little Bow ASP project, and any future expansions or additions to the project will not meet forecasted oil production targets. Specific risk factors associated with the production and reserves relating to our ASP project include the following, without limitation:

- reduced oil recovery from injected chemical due to factors such as injectant performance, reservoir sweep efficiency, injectant/mineralogical interactions, thief zones, injectant degradation due to operating conditions;
- reduced injectivity and/or productivity due to pipeline or other equipment failures, loss of injection or production wells, limitations in installed equipment capacity;
- geological complexities or features in the oil reservoir unknown at the time of project implementation which affect the effectiveness of injectant in oil recovery;
- operational interruptions in our injection facility, oil processing battery, field pipelines etc. due to mechanical failure, weather related interruptions, seasonal access issues, maintenance and etc.; and
- operational interruptions due to interruptions in third party facilities and services such as pipelines, chemical suppliers, chemical transport systems and electrical power supply.

There is a risk that capital projects, undertaken to support the existing scope of the Little Bow ASP Project and future expansions or additions to the project will not be completed on time or on budget. Additionally, there is a risk that such projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- conditions imposed by regulatory approvals;
- delays induced by weather;
- errors in construction;
- changes in project scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents including chemical spills or other environmental matters;
- permit requirement violation; and
- failure of existing wells, surface equipment, pipelines or other related facilities.

There is a risk that future capital costs for the chemical injectant utilized in the Little Bow ASP Project will be higher than forecast due to many factors, including without limitation:

- changes in foreign currency exchange rates;
- changes in vendor pricing;
- modifications to the project injection schedule and injection targets;
- changes in transportation charges; and
- interruptions in rail or other transport or logistical services.

Operating Costs

The operating costs of the project have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced by the project. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation:

- the amount and cost of labour to operate the project;
- the cost of chemicals;
- the cost of electricity;
- power outages, particularly in winter when freeze-ups could occur;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in heavy oil differentials could have an adverse effect on the anticipated returns from the project as well as our overall business, financial condition, results of operations and cash flows.

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See *Industry Conditions – Transportation Constraints and Market Access* and *Industry Conditions – Curtailment*. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in our inability to realize the full economic potential of our products or in a reduction of the price offered for our production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See *Industry Conditions – Regulatory Authorities and Environmental Regulation*. The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

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

Our business is impacted by a number of factors, including volatility of prices for oil and natural gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our petroleum and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completion (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, operating and other costs. Drilling hazards or environmental damage could greatly increase the cost of operations (including hydraulic fracturing), and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Operating costs for our underlying properties will directly impact the amount of cash flow received by us. Labour costs, electricity, gas processing, well servicing and chemicals are a few of our operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and consequently, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of our Common Shares.

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

There is a risk that interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and affect our ability to fund ongoing operations and could impact the market price of the Common Shares.

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. 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 related to the U.S. dollar will negatively affect our production revenue. Accordingly, Canadian/United States exchange rates could affect the future value of our as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

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.

Significant political events may cause uncertainty in financial and economic markets

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See *Industry Conditions - The North American Trade Agreement and Other Trade Agreements*. The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on our businesses, financial conditions, results of operations and valuation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in

North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction.

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

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development - particularly with respect to infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt our activities. See *Industry Conditions – Transportation Constraints and Market Access*.

Climate change may pose varied and far ranging risks to our business and operations, both known and unknown, that may adversely affect our business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

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

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the hydrocarbon industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

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

Acute Climate Change Risk

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

Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

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. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and natural gas companies that may be disproportionately affected by price instability. See *Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*.

We have been historically reliant on external sources of capital, borrowings and equity sales and, if unavailable, our financial condition will be adversely affected

Amounts paid in respect of interest and principal on debt may reduce future capital expenditures. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Although we believe our current cash positions and cash flow from operations will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

As future capital expenditures will be financed out of cash flows from operating activities, borrowings and possible future security issuances, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

From time to time we may enter into transactions which may be financed in whole or in part with debt. 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. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition and results of operations. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Shareholders may suffer dilution in connection with future issuances of Common Shares. In the normal course of making capital investments to maintain and expand our oil and gas reserves additional Common Shares may be issued. Additionally, from time to time we may issue Common Shares in order to finance significant acquisitions or development projects or to reduce debt and maintain a more optimal capital structure. Our success is, in part, dependent on our ability to raise capital from time to time by issuing additional Common Shares. Shareholders may suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to complete acquisitions.

The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. However, if cash flows from operating activities are lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties. See also, *Risk Factors – Risks Relating to Our Business and Operations*.

Our hedging activities may negatively impact our income and our financial condition

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2019, the unrealized gain/loss was nil compared to $1.2 million of unrealized gain in 2018, which resulted from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see *Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*.

We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. An increase in the Canada/U.S. foreign exchange rate will impact future dividends and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

Our current hedging contracts provide a benefit to us during this period of low oil and natural gas prices by providing a floor price for a significant amount of production. This benefit will only be realized for the period and for the commodity quantities in those contracts. The benefits from such derivatives contracts will be realized by the end of June, 2018. Additional hedges might not be available at prices similar to our current hedge prices, which could adversely impact our revenues.

Our obligations under our hedging contracts are secured by a floating charge on our assets. If we fail to comply with the covenants in our hedging contracts, it could result in seizure and/or sale of our assets. We are also exposed to counterparty credit risk as a result of our hedging contracts.

Failure of third parties to meet their contractual obligations to us may have a material adverse effect on our financial condition

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such parties 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 impact 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, we may be 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.

Our business is heavily regulated and such regulation increases our costs and may adversely affect our financial condition

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

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

Continued uncertainty in the industry may restrict the availability or increase the cost of borrowing required for future development and acquisitions

Due to the conditions in the oil and gas industry and/or global economic conditions and the domestic lending landscape, 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. Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our cash flow. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to access sufficient capital for our capital expenditures and acquisitions could be impaired and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

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

There are numerous uncertainties inherent in estimating quantities of recoverable petroleum and natural gas reserves, including many factors beyond our control

Although we, together with McDaniel, have carefully prepared the reserves figures included in this Annual Information Form and believe that the methods of estimating reserves have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced.

In general, estimates of economically recoverable petroleum and natural gas reserves and the future net revenues therefrom 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 petroleum and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable petroleum 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.

The reserves and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by McDaniel and such variations could be material. The McDaniel Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, NGLs and natural gas and they are substituted for the price assumptions utilized in the McDaniel Report, the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the McDaniel Report are based, in part, on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the McDaniel Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the McDaniel Report.

Estimates of proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

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

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases, oil and natural gas spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental hazards, fires, transport accidents and spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as we undertake more exploratory activity. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, the shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and 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. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition.

There is 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.

Exploration and development risks arise due to the uncertain results of searching for and producing petroleum and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up to date technology to enhance methods and controlling costs to maximize returns.

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.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately six percent of our properties are operated by third parties, based on daily production. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including 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 recourse 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. Any of these factors could materially adversely affect our financial and operational results. See *Industry Conditions – Liability Management Rating Program*.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses. Our return on assets operated by others therefore will depend upon a number of factors that may be outside of our control, including 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. 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.

Delays in business operations could adversely affect the market price of the Common Shares

Delays in business operations could adversely affect the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline or processing capacity;
- operational problems affecting pipelines and facilities;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could expose us to additional third party credit risks.

The marketability of petroleum and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control

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

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

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

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

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

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

Hydraulic fracturing is subject to certain risks

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 natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing extensively in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delays or increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Regulatory water use restrictions and/or limited access to water or other fluids may impact our production volumes from our waterfloods

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

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.

Changes in government regulations that affect the oil and natural gas industry could adversely affect us

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse impact on us.

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

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. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See *Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*. Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with counterparts who operate in jurisdictions where there are less costly carbon regulations..

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Changes in tax and other laws may adversely affect Shareholders. Income tax laws, other laws or government incentive programs relating to the oil and natural gas industry, such as resource allowance, may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. Tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Shareholders.

The oil and natural gas industry is subject to extensive controls and regulations governing our operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and the United States, all of which should be carefully considered by investors in the oil and natural gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects.

We cannot assure you that income tax laws and government incentive programs relating to the oil and natural gas industry will not change in a manner that adversely affects the market price of the Common Shares.

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

We may not be able to realize the anticipated benefits of acquisitions and dispositions or to manage growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our 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 assets and operations with our operations. The integration of acquired business 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 and the resources required to provide such services. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that we can focus our efforts and resources more efficiently. Depending on market conditions for such non-core assets, certain of our non-core assets, if disposed of, may realize less than their carrying value on our financial statements.

The price we pay for the purchase of any material properties is based on several criteria, including engineering and economic assessments made by independent engineers modified to reflect our technical and economic views. These assessments include a series of assumptions regarding such factors as recoverability and marketability of petroleum and natural gas, future prices of petroleum and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities.

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

There is strong competition relating to all aspects of the oil and natural gas industry

There are numerous companies in the oil and natural gas industry, who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other organizations have significantly greater technical, financial and operational resources than us.

The operations and management require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans. We compete with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. If we are unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

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

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

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

Our petroleum and natural gas reserves are a depleting resource and decline as such reserves are produced

Absent commodity price increases or cost effective acquisition and development activities, our cash flows from operating activities will decline over time in a manner consistent with declining production from typical petroleum and natural gas reserves. Our future petroleum and natural gas reserves and production, and therefore our cash flows from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

If external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our petroleum and natural gas reserves may be impaired. To the extent that we use cash flows from operating activities to finance capital expenditures or property acquisitions, the level of cash flows from operating activities available for distribution to Shareholders will be reduced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;

- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

We only operate in western Canada and the United States and expansion outside of these areas may increase our risk exposure

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

Our success depends in large measure on the activities of our key personnel

Our operations require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans which could have a material adverse effect on our business, financial condition, results of operations and prospects.

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

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration and development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. We are not aware of any material claims having been made in respect of our properties and assets; however, if a claim arose and was successful this may have a material adverse effect on our results of operations and business.

Our actual title to and interest in our properties, and our right to produce and sell the oil and natural gas therefrom, may vary from our records. In addition, there may be valid legal challenges or legislative changes that affect our title to and right to produce from our oil and natural gas properties, which could impair our activities and result in a reduction of the revenue received by us. If a defect exists in the chain of title or in our right to produce, or a legal challenge or legislative change arises, it is possible that we may lose all, or a portion of, the properties to which the title defect relates and/or our right to produce from such properties. This may have a material adverse effect on our business, financial condition, results of operations and prospects.

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

Our permitted investments may be risky

An investment in us should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy related companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of our Common Shares could be affected by adverse changes in the market values of such investments.

A shortfall in the supply of diluent may increase our costs

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing our overall operating cost, decreasing our net revenues and negatively impacting the overall profitability of our heavy oil and bitumen projects.

We may become involved in, named as a party to, or be the subject of, various legal proceedings

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

In addition, 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 commence lawsuits against others who we believe are infringing upon our rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of process 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. We may not be successful in such development or acquisition or that such licences would 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.

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 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.

Breaches of our cyber-security and loss of, or access to, electronic data may adversely impact our 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 a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information.

Risks Relating to Ownership of Common Shares

Our Board of Directors has discretion in the payment of dividends

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice The amount of future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including 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 the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our Board of Directors and management team, we will change our dividend policy from time to time and, as a result, any future cash dividends could be reduced or suspended entirely. The future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

Changes in market-based factors may adversely affect the trading price of the Common Shares

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

Certain Risks for United States and Other Non-Resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada and our principal office is located in Calgary, Alberta. All of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is the U.S. Loan Agreement, which has been filed on SEDAR at www.sedar.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during the most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

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 most recently completed 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 we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of our directors and senior officers, any holder of Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last three financial years or during the current financial year which has materially affected or would materially affect us.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 – Continuous Disclosure

Obligations by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our auditors.

None of the "designated professionals" (as that term is defined in National Instrument 51-102) of McDaniel had any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Chartered Professional Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associate or affiliate entities, except that Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which is a law firm that renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at www.sedar.com and on our website at www.zargon.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular – proxy statement dated May 4, 2020 relating to our annual Shareholders meeting to be held on June 1, 2020. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2019 and the related management's discussion and analysis.

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

Zargon Oil & Gas Ltd.
1100, 112 – 4th Avenue S.W.
Calgary, Alberta, T2P 0H3
Tel: (403) 264-9992
Fax: (403) 265-3026

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(Form 51-101F3)

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

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

The Audit and Reserves Committee of the board of directors of Zargon has

(a) reviewed Zargon's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Audit and Reserves Committee of the board of directors has reviewed Zargon'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 Audit and Reserves Committee, approved

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data or prospective resources data; and

(c) the content and filing of this report.

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

(signed) C.H. Hansen
President and Chief Executive Officer

(signed) C.M. Hustad
Vice President, Development

(signed) Ron Wigham
Director and Member of the Audit and Reserves Committee

(signed) G.C. Merritt
Director and Member of the Audit and Reserves Committee

January 21, 2020

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

To the board of directors of Zargon Oil & Gas Ltd. ("**Zargon**"):

1. We have evaluated Zargon'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 Zargon's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Zargon evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to Zargon's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2019	Canada	$nil	$32,827	$nil	$32,827
		United States	$nil	$24,428	$nil	$24,428

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

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

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

January 21, 2020

APPENDIX C

MANDATE & TERMS OF REFERENCE OF THE AUDIT AND RESERVES COMMITTEE

Role and Objective

The Audit and Reserves Committee (the "**Committee**") is appointed by the Board of Directors (the "**Board**") of Zargon Oil & Gas Ltd. ("**Zargon**" or the "**Corporation**"), to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements, the audited financial statements and other mandatory disclosure releases containing financial information, and reviewing the annual independent report of the Corporation's petroleum and natural gas reserves and recommending all, for board of director approval.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Zargon, none of whom are members of management of Zargon and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 - *Audit Committees* ("**MI 52-110**") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). Committee members shall also meet the independence requirements of the regulatory bodies to which the Corporation may be subject to.

2. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

3. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

Mandate and Responsibilities of Committee

1. The Committee shall, in addition to any other duties and responsibilities specifically delegated to it by the Board, generally assume responsibility for developing the approach of the Corporation to matters concerning all financial information and disclosure and all petroleum and natural gas reserves information and disclosure and, from time to time, shall review and make recommendations to the Board as to such matters. Specifically, the Committee will have the authority and responsibility for:

    (a) Audit Matters:

    (i) To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Zargon and related matters;

    (ii) To provide better communication between directors and external auditors;

    (iii) To enhance the external auditor's independence;

    (iv) To increase the credibility and objectivity of financial reports;

    (v) To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors;

    (vi) It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting;

(vii) It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Zargon's Internal Control Systems:

A. Identifying, monitoring and mitigating business risks; and

B. Ensuring compliance with legal, ethical and regulatory requirements.

(viii) It is a primary responsibility of the Committee to review the annual financial statements of Zargon prior to their submission to the board of directors for approval. The process should include but not be limited to:

A. Reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

B. Reviewing significant accruals, reserves or other estimates such as the impairment test calculation;

C. Reviewing accounting treatment of unusual or non-recurring transactions;

D. Ascertaining compliance with covenants under loan agreements;

E. Reviewing disclosure requirements for commitments and contingencies;

F. Reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

G. Reviewing unresolved differences between management and the external auditors; and

H. Obtain explanations of significant variances with comparative reporting periods.

(ix) The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Zargon's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

(x) With respect to the appointment of external auditors by the board, the Committee shall:

A. Recommend to the board the appointment of the external auditors;

B. Recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

C. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

D. Review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

(xi) Review with external auditors (and internal auditor if one is appointed by Zargon) their assessment of the internal controls of Zargon, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Zargon and its subsidiaries.

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

(xiii) The Committee shall review risk management policies and procedures of Zargon (i.e. hedging, litigation and insurance).

(xiv) The Committee shall establish a procedure for:

A. The receipt, retention and treatment of complaints received by Zargon regarding accounting, internal accounting controls or auditing matters; and

B. The confidential, anonymous submission by employees of Zargon of concerns regarding questionable accounting or auditing matters.

(xv) The Committee shall review and approve Zargon's hiring policies regarding employees and former employees of the present and former external auditors of Zargon.

(xvi) The Committee shall have the authority to investigate any financial activity of Zargon. All employees of Zargon are to cooperate as requested by the Committee.

(xvii) The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Zargon without any further approval of the board.

(b) Reserves Matters:

(i) In conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;

(ii) After consultation with the Corporation's senior engineering management recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

(iii) In consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;

(iv) Review both the procedures for providing petroleum and natural gas reserves information to the independent evaluating engineers and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

(v) In consultation with the Corporation's senior engineering management and the independent evaluating engineers:

A. Determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserves data without reservations; and

B. Review the reserves data and the report of the independent evaluating engineers.

(vi) Recommend to the Board for filing, the report from the independent evaluating engineers and/or senior engineering management on the Corporation's petroleum and natural gas reserves data;

(vii) Ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements;

(viii) Review any proposals to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

(ix) Meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;

(x) Meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting; and

(xi) Co-ordinate meetings with the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves.

Meeting and Administrative Matters

1. Meetings of the Committee should be scheduled to take place at least four (4) times per year. Special meetings may be convened as required upon the request of the Committee Chairman or the CEO. The President and Chief Executive Officer and the Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman

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

3. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board of Directors may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee

4. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee

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

6. Unless otherwise designated by the Board, the members of the Committee shall elect a Chairman from among the members and the Chairman shall preside at all meetings of the Committee. The Chairman of the Committee shall have a second and deciding vote in the event of a tie. In the absence of the Chairman, the members of the Committee shall appoint one of their members to act as Chairman. Notwithstanding the foregoing, in all circumstances the Chairman must be an outside director, unrelated to the Corporation

7. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board

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

9. The Committee may obtain information from any employee of the Corporation and the Corporation's agents that it may require to carry out this mandate. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation, as determined by the Committee

10. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair

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

12. Review annually the Committee mandate and terms of reference and recommend any changes to the Board.