BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2018

March 12, 2019

TABLE OF CONTENTS

GLOSSARY OF TERMS

Unless the context otherwise requires, in this Annual Information Form, the following terms and abbreviations have the meanings set forth below.

"Bonterra" means Bonterra Energy Corp. the Company formed on amalgamation of Bonterra Corp. and Bonterra Oil & Gas Ltd. effective January 1, 2010;

"Bonterra Corp." means Bonterra Energy Corp. a former wholly owned subsidiary of Bonterra Trust which was wound-up and dissolved January 1, 2010;

"**Bonterra Oil & Gas Ltd.**" means the former corporation whose assets consisted of all the issued and outstanding trust units of Bonterra Trust;

"Bonterra Trust" means Bonterra Energy Income Trust;

"Economic Life" means, with respect to an oil and gas property, the time remaining before production of petroleum substances from the property is forecast to be uneconomic;

"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;

"Reserve Life Index" or **"RLI"** is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current production rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the annualized fourth quarter production from the preceding 12 month period;

"Shareholder" means a holder of Bonterra common shares;

"Sproule" means Sproule Associates Limited, independent petroleum consultants;

"Sproule Report" means the independent engineering evaluation of Bonterra's oil, natural gas and NGLs interests prepared by Sproule dated February 8, 2019, and effective December 31, 2018 utilizing commodity price forecasts of Sproule dated December 31, 2018; and

"Trustee" means Odyssey Trust Company, or its successor as trustee of the Company.

ABBREVIATIONS

Oil and Natural Gas Liquids	Natural Gas
Bbl – barrels	GJ – gigajoules
MBbl – thousand barrels	GJ/d – gigajoules per day
Bbl/d – barrels per day	Mcf – thousand cubic feet
NGLs – natural gas liquids	MMcf – million cubic feet
	MMbtu – million British thermal units
	Bcf – billion cubic feet
	Mcf/d – thousand cubic feet per day

Other

AECO means Alberta Energy Company interconnect with the NOVA System.

BOE means barrel of oil equivalent. In all cases of this document, a BOE conversion ratio for natural gas of 6 Mcf:1Bbl has been used. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading, particularly if used in isolation.

MBOE means thousand BOE.

BOE/d means BOE per day.

WTI means West Texas Intermediate at Cushing, Oklahoma, the benchmark crude oil for pricing purposes.

GCA means gas cost allowance deduction taken off of provincial (Crown) royalties, to offset the capital and direct operating costs associated with processing the Crown’s share of raw gas at a gas plant, and transporting the Crown’s share of residue gas through a sales line.

CONVERSIONS

The following table sets forth certain standard 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
Bbl	Cubic Metres	0.159
Cubic Metres	Bbl	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

ADVISORY

In this Annual Information Form where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil, based on the current market prices thereof, is significantly different from the energy equivalency ratio of six to one, utilizing a BOE conversion ratio on this basis may be misleading as an indication of value.

Unless otherwise specified, references to oil include oil and NGLs. NGLs include condensate, propane, butane and ethane.

Where any disclosure of reserves data is made in this Annual Information Form or the documents incorporated by reference herein that does not reflect all of the reserves of Bonterra, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of the reserves and future net revenue for all properties, due to the effects of aggregation.

PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this Annual Information Form or the documents incorporated by reference herein, has been prepared and presented in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). The actual oil and gas reserves and future production will be greater than or less than the estimates provided herein. The estimated value of future net revenue from the production of the disclosed oil and gas reserves does not represent the fair market value of these reserves. There is no assurance that the forecast prices and costs or other assumptions made in connection with the reserves disclosed herein will be attained and variances could be material.

DEFINITIONS AND NOTES TO RESERVE DATA TABLES

Certain terms used herein are defined in NI 51-101 or the Canadian Oil and Gas Evaluation Handbook (COGE Handbook) and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101 or the COGE Handbook.

The following definitions form the basis of the classification of reserves and values presented in the Sproule Report. Reserve data tables may not add due to rounding.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable, and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. These concepts are presented and discussed in greater detail within the guidelines in Section 5.5 of the COGE Handbook.

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered 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, which are generally accepted as being reasonable, and shall be disclosed.

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

1. Proved Reserves

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.

2. Probable 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.

3. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this Annual Information Form.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories.

4. Developed Reserves

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

5. Developed Producing Reserves

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.

6. Developed Non-Producing Reserves

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.

7. Undeveloped Reserves

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

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation is typically 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.

8. Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 above are applicable to individual reserves entities, which refers to the lowest level at which reserves calculations are performed, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are presented.

Reported reserves should target the following levels of certainty under a specific set of economic conditions:

a) At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
b) At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
c) At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves plus possible reserves.

A quantitative 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 are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5 of the COGE Handbook.

CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking statements. These statements relate to future events or Bonterra's future performance. All statements other than statements of historical fact may be forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In addition, this Annual Information Form and documents incorporated by reference herein may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this Annual Information Form and the documents incorporated by reference herein include, but are not limited to, statements with respect to:

- the quantity and quality of the oil and natural gas reserves;
- the performance and characteristics of Bonterra's oil and natural gas properties;
- future development and exploration activities and the timing thereof;
- future land expiries;
- results of various projects of Bonterra;
- timing of receipt of regulatory approvals;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Bonterra;
- supply and demand for oil, NGLs and natural gas;

- expectations regarding Bonterra's ability to raise capital and to continually add to reserves through development and acquisitions;
- the impact of Canadian federal and provincial governmental regulation on Bonterra relative to other natural resource issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- projections of commodity prices and costs;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

Although Bonterra believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Bonterra cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither Bonterra nor any other person assumes responsibility for the outcome of the forward-looking statements. Many of the risks and other factors are beyond Bonterra's control, which could cause results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein. The risks and other factors include, but are not limited to:

- general economic conditions in Canada, the United States and globally, including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, NGLs and natural gas;
- liabilities inherent in oil and natural gas operations;
- the ability to generate sufficient cash flow from operations and other sources to meet current and future obligations, including costs of projects and repayment of debt;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- the uncertainty of reserve estimates and reserve life;
- weather;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- health, safety and environmental risks;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions or reserves, deposits, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- rights to surface access;
- the ability of management to execute its business plan;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "Risk Factors" in this Annual Information Form.

These factors should not be considered as exhaustive. Statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources, reserves and deposits described can be profitably produced in the future. With respect to forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein, Bonterra has made assumptions regarding: future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; current technology; cash flow; production rates; timing and amount of capital expenditures; the prices and marketability of oil, NGLs and natural gas; royalty rates; effects of regulation by governmental agencies; future operating costs; and the company's ability to obtain financing on acceptable terms. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Bonterra's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Bonterra is not under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.

STRUCTURE OF BONTERRA ENERGY CORP.

Bonterra Energy Corp.

Bonterra Energy Corp. ("Bonterra" or "the Company") is a dividend paying, oil and gas company headquartered in Calgary, Alberta. The Company's assets consist of crude oil and natural gas assets.

The head and principal office of Bonterra is located at:
901, 1015 4th Street S.W., Calgary, Alberta, T2R 1J4.

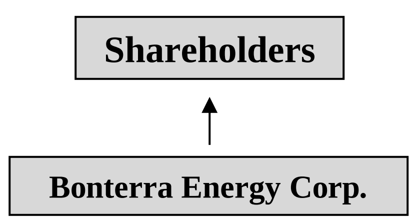
The Company's primary focus is to maximize total return to shareholders by growing production and maintaining and enhancing cash dividends through the optimum utilization and development of existing crude oil and natural gas properties and acquisition and development of new producing or undeveloped properties. Currently, development efforts are focused in the Cardium zone of the Pembina and Willesden Green fields located in west central Alberta.

Transfer Agent and Registrar

The Registrar and Transfer Agent for the common shares is Odyssey Trust Company at 350, 300 5th Ave SW Calgary, Alberta T2P 3C4

Organization Chart

At December 31, 2018, the structure of Bonterra was as set forth below:



The common shares trade under the symbol BNE on the Toronto Stock Exchange (TSX).

Bonterra Energy Corp. was formed effective January 1, 2010 when Bonterra Oil & Gas Ltd. wound up Bonterra Energy Income Trust ("Bonterra Trust") and amalgamated with its wholly owned subsidiary Bonterra Energy Corp. pursuant to the provisions of the Canada Business Corporations Act to continue as one corporation under the name Bonterra Energy Corp. effective January 1, 2010.

Prior to the amalgamation, Bonterra Trust (a trust which was wholly owned by Bonterra Oil & Gas Ltd.) was wound-up and dissolved in accordance with subsection 88.1 of the Income Tax Act (Canada). As a result of the amalgamation and dissolution of Bonterra Trust, Bonterra holds all of the assets formerly held by the former subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Property and Corporate Acquisitions and Dispositions in 2018, 2017 and 2016

On July 24, 2018, Bonterra acquired certain Cardium focused oil and gas assets in the Pembina area from a junior oil and gas producer for $3.1 million before adjustments financed through bank debt. The transaction had an effective date of April 1, 2018.

On December 20, 2017, the Company sold a two percent gross overriding royalty (GORR) on all of the production from the Company's Pembina Cardium pool effective January 1, 2018. The royalty has the option of either being paid in cash or in kind. Consideration for this asset was $56,747,000, comprised of $52,000,000 in cash and Cardium assets valued at $4,747,000 in property, plant and equipment.

On September 7, 2016, Bonterra acquired certain Cardium focused oil and gas assets in the Pembina area from a senior oil and gas producer for $2.0 million before adjustments financed through bank debt. The transaction had an effective date of April 1, 2016.

Legal Proceedings

There are no material legal proceedings to which Bonterra is subject or which is known by the Company to be contemplated.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

PART I – DATE OF STATEMENT

The reserves data and other oil and gas information set forth below is based upon an evaluation by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator within the meaning of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) with an effective date of December 31, 2018 contained in the Sproule Report dated February 8, 2019.

PART II– DISCLOSURE OF RESERVE DATA

The reserves data summarizes the oil, liquids and natural gas reserves of Bonterra and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data conforms to the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Bonterra believes is important to the readers of this information. Bonterra engaged Sproule to provide an evaluation of Proved and Probable Reserves and no attempt was made to evaluate possible reserves.

Readers should not assume that the estimates of future net revenues presented in the tables below 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 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. For more information as to the risks involved see "Risk Factors – Oil and Natural Gas Prices" and "Risk Factors – Reserves".

In accordance with the requirements of NI 51-101, attached hereto are the following appendices: 1) Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2018 pricing assumptions; and 2) Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.

FORM 51-101F1 PART 2.1(1)
SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total	
Reserves Catelgory:	Gross (MBbl)	Net (MBbl)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (Mbbl)	Gross (MBoe)	Net (MBoe)
PROVED								
Developed Producing	23,864.0	21,459.9	76,272.0	70,101.0	3,274.6	2,589.5	39,850.7	35,733.0
Developed Non-Producing	683.6	625.8	1,707.0	1,577.0	56.7	44.9	1,024.8	933.6
Undeveloped	23,337.6	20,591.2	75,994.0	69,788.0	3,755.1	3,279.2	39,758.4	35,501.8
TOTAL PROVED	47,885.2	42,676.9	153,973.0	141,466.0	7,086.4	5,913.6	80,633.9	72,168.4
PROBABLE	12,181.6	10,062.7	39,406.0	36,078.0	1,842.0	1,494.4	20,591.4	17,570.1
TOTAL PROVED PLUS PROBABLE	60,066.8	52,739.6	193,379.0	177,544.0	8,928.4	7,408.0	101,225.3	89,738.5

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(2)
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

Net Present Values of Future Net Revenue Before Income Taxes
Discounted at (%/Year)

($ Millions) Reserves Category[(1)]	0%	5%	10%	15%	20%	Unit Value Discounted at 10%/YR ($/BOE)
PROVED						
Developed Producing	1,289.0	922.9	715.6	586.1	498.6	20.0
Developed Non-Producing	27.2	18.0	13.1	10.1	8.1	14.0
Undeveloped	1,024.4	601.3	379.7	251.8	172.0	10.7
TOTAL PROVED	2,340.6	1,542.2	1,108.3	848.0	678.7	15.4
PROBABLE	858.3	455.5	293.0	212.0	164.7	16.7
TOTAL PROVED PLUS PROBABLE	3,198.9	1,997.7	1,401.3	1,060.0	843.5	15.6

(1) Unit values are based on net reserves.

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(2)
SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

Net Present Values of Future Net Revenue After Income Taxes
Discounted at (%/Year)

($ Millions) Reserves Category	0%	5%	10%	15%	20%
PROVED					
Developed Producing	1,091.5	804.0	637.7	531.9	459.1
Developed Non-Producing	20.0	13.2	9.7	7.5	6.1
Undeveloped	744.3	423.4	253.8	156.2	95.9
TOTAL PROVED	1,855.8	1,240.6	901.2	695.6	561.1
PROBABLE	626.9	332.6	213.7	154.6	120.1
TOTAL PROVED PLUS PROBABLE	2,482.7	1,573.3	1,114.9	850.2	681.3

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(b)
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

($ Millions) Reserves Catergory:	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
PROVED	5,642.1	624.5	1,958.8	616.0	102.1	2,340.6	484.8	1,855.8
PROVED PLUS PROBABLE	7,354.0	898.6	2,516.5	626.1	113.8	3,198.9	716.3	2,482.7

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(c)
NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($ Millions)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/BOE)[1]
Proved	Light And Medium Crude Oil (Including solution gas and associated by-products)	1,096.2	16.03
	Conventional Natural Gas (Including associated by-products)[2]	12.2	3.24
Total		1,108.4	
Proved Plus Probable	Light And Medium Crude Oil (Including solution gas and associated by-products)	1,381.0	16.26
	Conventional Natural Gas (Including associated by-products)[2]	20.4	4.27
Total		1,401.4	

(1) Unit values are based on net reserves.
(2) Includes corporate GCA, if applicable.

The Company only operates in Canada.

PART III – PRICING ASSUMPTIONS

Forecast Prices

The Forecast Prices used in the appendix are:

Year	Canadian Light Sweet Crude 40° API ($Cdn/bbl)	Natural Gas AECO-C Spot ($Cdn/MMbtu)	NGL Butanes Edmonton ($Cdn/ bbl)	NGL Propane Edmonton ($Cdn/ bbl)	NGL Pentanes Edmonton ($Cdn/bbl)	Operating Cost Inflation Rate (%/Yr)	Capital Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
HISTORICAL								
2014	93.99	4.50	68.02	44.42	102.39	2.0	(1.0)	0.91
2015	57.45	2.70	36.81	6.17	61.45	1.8	(18.7)	0.78
2016	52.80	2.18	34.32	13.60	55.71	1.2	(9.7)	0.76
2017	61.84	2.19	44.11	28.77	67.21	1.7	2.4	0.77
2018	68.63	1.52	34.11	27.30	79.47	2.5	4.2	0.77
FORECAST(1)(2)								
2019	75.27	1.95	40.91	30.27	75.32	-	-	0.77
2020	77.89	2.44	50.25	34.51	80.00	2.0	2.0	0.80
2021	82.25	3.00	56.88	38.15	83.75	2.0	2.0	0.80
2022	84.79	3.21	58.01	39.64	85.50	2.0	2.0	0.80
2023	87.39	3.30	59.17	40.62	87.29	2.0	2.0	0.80
2024	89.14	3.39	60.36	41.62	89.11	2.0	2.0	0.80
2025	90.92	3.49	61.56	42.64	90.96	2.0	2.0	0.80
2026	92.74	3.58	62.79	43.68	92.86	2.0	2.0	0.80
2027	94.60	3.68	64.05	44.75	94.79	2.0	2.0	0.80
2028	96.49	3.78	65.33	45.83	96.76	2.0	2.0	0.80
2029	98.42	3.88	66.64	46.94	98.77	2.0	2.0	0.80

(1) Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.

(2) The forecasted prices were provided by the independent reserves evaluator Sproule Associates Limited.

The Company's weighted average realized prices by production type for the 2018 financial year are as follows:

Light and Medium Crude Oil ($ per barrel)	65.51
Conventional Natural Gas ($ per Mcf)	1.63
Natural Gas Liquids ($ per barrel)	40.32

PART IV – RECONCILIATION OF CHANGES IN RESERVES

RECONCILIATION OF COMPANY GROSS RESERVES (BEFORE ROYALTY) BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2018 FORECAST PRICES AND COSTS

	Light and Medium Crude Oil (MBbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
PROVED				
December 31, 2017	**48,745.9**	**141,376**	**6,283.5**	**78,592.1**
Extensions[1]	3,488.2	7,404	507.8	5,230.0
Technical Revisions	(2,040.4)	14,020	555.3	850.9
Discoveries	-	-	-	-
Acquisitions	443.4	1,869	116.0	871.4
Dispositions	-	-	-	-
Economic Factors	211.7	(1,736)	(13.0)	(90.3)
Production	(2,963.6)	(8,960)	(363.2)	(4,820.2)
December 31, 2018	**47,885.2**	**153,973**	**7,086.4**	**80,633.9**
PROBABLE				
December 31, 2017	**13,147.9**	**38,498**	**1,684.0**	**21,248.3**
Extensions[1]	832.4	1,867	131.8	1,275.2
Technical Revisions	(1,866.8)	(1,412)	(7.3)	(2,109.7)
Discoveries	-	-	-	-
Acquisitions	131.6	629	39.0	275.6
Dispositions	-	-	-	-
Economic Factors	(63.5)	(176)	(5.5)	(98.0)
Production	-	-	-	-
December 31, 2018	**12,181.6**	**39,406**	**1,842.0**	**20,591.4**
PROVED PLUS PROBABLE				
December 31, 2017	**61,893.8**	**179,874**	**7,967.5**	**99,840.4**
Extensions[1]	4,320.6	9,271	639.6	6,505.2
Technical Revisions	(3,907.2)	12,609	548.0	(1,258.8)
Discoveries	-	-	-	-
Acquisitions	575.0	2,498	155.1	1,147.0
Dispositions	-	-	-	-
Economic Factors	148.2	(1,912)	(18.5)	(188.3)
Production	(2,963.6)	(8,960)	(363.2)	(4,820.2)
December 31, 2018	**60,066.8**	**193,380**	**8,928.4**	**101,225.3**

(1) Included in extensions is infill drilling.

The Company only operates in Canada.

PART V – ADDITIONAL INFORMATION RELATED TO RESERVE DATA

Undeveloped Reserves

Company Gross Reserves – First Attributed by Year [1]

Proved Undeveloped Reserves

	Light and Medium Crude Oil (MBbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (MBbl)		Total (MBOE)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
2016	3,425	21,107	8,629	57,109	371	2,326	5,234	32,951
2017	4,438	22,369	7,325	65,914	403	3,068	6,062	36,423
2018	3,303	23,338	7,308	75,994	494	3,755	5,016	39,759

Probable Undeveloped Reserves

	Light and Medium Crude Oil (MBbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (MBbl)		Total (MBOE)	
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
2016	909	5,693	2,054	19,452	95	804	1,356	9,739
2017	1,159	6,183	1,902	18,547	105	839	1,581	10,114
2018	799	6,200	1,874	19,451	131	981	1,241	10,423

(1) First attributed refers to reserves first attributed at year end of the corresponding fiscal year.

Sproule's evaluation of Bonterra's reserves as of December 31, 2018 is in accordance with the Canadian Oil and Gas Evaluation Handbook Third Edition 2018 (the "COGE Handbook").

In some situations, development forecasts of undeveloped petroleum and natural gas volumes have extended beyond the development timing guidance in the COGE Handbook (three years for assignment of proved undeveloped reserves, and five years for the assignment of probable undeveloped reserves) as the result of other factors which are not contingencies. This delay has no consequent impact on the confidence level associated with the reserves estimate in each category, and the Company has provided assurance of their corporate commitment for development. In the following section, the properties, the timing for the extended development plan and the rationale is documented.

Reserves in the Cardium Resource Play

The vast majority of the Company's reserves occur in the Pembina and Willesden Green Cardium fields located in central Alberta. There are 341 drilling locations in the Cardium to which proved undeveloped and proved plus probable undeveloped reserves have been assigned. The Cardium resource play includes extensive on-going development. Development deferral is designed to align future capital investments with future cash flow in a capital constrained environment.

There are 172 drilling locations with future development plans that differ from the COGE Handbook guidance for larger capital expenditures of three years for assigning proved undeveloped reserves. There are 83 future drilling locations scheduled to be developed in the fourth year (2022) and 89 future drilling locations scheduled to be developed in the fifth year (2023) to which proved undeveloped reserves were assigned.

The development timing of the Cardium Resource Play is consistent with the COGE Handbook guidance:

"Ongoing Resource Play Development: For resource plays where drilling programs have been underway for a few years and are expected to continue for some time due to a larger inventory of locations that qualify for assignment as Reserves, it is reasonable to have Proved Undeveloped Reserves assigned for five years of development drilling and Probable Undeveloped Reserves extending out for ten years of development drilling."

Non-Cardium Conventional Plays

The following table lists two non-Cardium properties with future development plans that differ from the COGE Handbook guidance.

Properties	Final Year of Development Plan		Rationale for Development Timing
	Proved	Probable	
AB Single Well Gas Batteries (SWBG)	2023	2023	Deferral of ongoing development was motivated by market conditions that required a change in company strategy. In a capital constrained environment, new plant capacity is difficult to justify. Alternatively, the development plan ensures a source of supply to support existing processing capacity.
Tomahawk NonOp + Op	2023	2023	

Bonterra's proved undeveloped reserves amount to 39,759 MBOE and represent approximately 49.3 percent of the total proved reserves and 39.3 percent of total proved plus probable reserves. 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. In general, proved undeveloped reserves were assigned to certain properties as a result of Bonterra's capital program. Bonterra plans to convert the undeveloped reserves to proved developed producing reserves over the next five years.

Bonterra's probable undeveloped reserves amount to 10,423 MBOE and represent approximately 10.0 percent of the total proved plus probable reserves. Probable undeveloped reserves are assigned for similar reasons and generally to the same properties as proved undeveloped reserves. 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.

Significant Factors or Uncertainties

For significant factors and uncertainties affecting components of reserves data please see discussions under "Risk Factors" in this Annual Information Form and "Management's Discussion and Analysis" as contained in the Company's 2018 Annual Report.

Future Development Costs

$ 000s	Forecast Prices and Costs	
Year	Proved	Proved Plus Probable
2019	64,067	64,067
2020	124,937	124,937
2021	131,127	136,766
2022	147,733	150,608
2023	148,171	149,683
Total Undiscounted	616,035	626,061

The above future development costs will be funded primarily from 2019 to 2023 cash flow from operations, exercising of employee share options and if required from the Company's line of credit. Should these sources of funds be insufficient the Company will access the public markets as required.

PART VI – OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Primarily all of Bonterra's oil and natural gas properties are located in the Province of Alberta. The Company also has non-core properties located in the Provinces of Saskatchewan and British Columbia. In 2018, production volumes from Bonterra's properties were approximately 69 percent light and medium crude oil and NGLs and 31 percent conventional natural gas on a BOE basis. During the year ended December 31, 2018, Bonterra's oil and natural gas properties yielded average production of 13,206 BOE per day (2017 – 12,827 BOE per day, 2016 – 12,650 BOE per day). As at December 31, 2018 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 101,225 MBOE.

Pembina and Willesden Green Area, West Central Alberta

Properties

The Pembina and Willesden Green Cardium fields are Bonterra’s major properties located in central Alberta. The Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original oil in place with very low recoveries. Combined, they are the Company’s largest producing asset and represent 99.0 percent of Proved plus Probable reserves.

The Pembina Cardium field is the largest conventional oil field in Canada with an estimate of original oil in place (OOIP) of 10.6 billion barrels with less than 15 percent produced to date. This field has proved to be a significant area for multi-zone oil and natural gas exploration with predictable results. Horizontal drilling with multi stage fracking drastically improves recoveries from areas developed with vertical drilling and extends the economic edge of the reservoir where vertical drilling is not economic. Bonterra operates approximately 90 percent of its production with an average land working interest of 76 percent.

Bonterra has identified 1,035 gross (731 net) potential Cardium horizontal drilling locations within its acreage. Currently only 341 gross (294 net) undeveloped Cardium horizontal drilling locations are reflected in Bonterra's 2018 reserve report.

During 2018 the Company invested approximately $65.0 million to drill, complete and tie-in 34 gross (28.0 net) horizontal wells in the Cardium formation with a 100 percent success rate. The Company also invested approximately $10 million on related infrastructure, recompletions and other capital during 2018. In addition, $3.7 million was incurred in 2018 related to exploration and evaluation assets and incremental Cardium assets.

Facilities

Bonterra operates approximately 67 oil batteries of various capacities in the Pembina area. Oil is gathered via pipeline or trucked to the batteries for processing. Treated oil is transferred into the Pembina midstream gathering system for transportation to Edmonton. Solution gas is separated at the batteries and pipeline connected to either the Pembalta stations, Keyera MBL, Keyera Lodgepole, Conoco Lodgepole, Conoco Sand Creek, Suncor Ferrier or Bonterra Keystone gas plants.

Shaunavon Area, Southwest Saskatchewan

Properties

Bonterra’s Shaunavon properties are located in the Chambery field and produce medium density crude oil from the upper Shaunavon formation currently under waterflood. Annual production for 2018 was 167 BOE per day (net). The wells in this area are generally long-life with stable and low-decline production profiles.

Facilities

Bonterra has ownership in all facilities required to process its Shaunavon production. All oil production is processed through owned and operated facilities for emulsion treating and water disposal. All natural gas produced is used for fuel gas in the production and processing of the oil, therefore, no processing facilities are required for processing solution gas.

Prespatou Area, Northeast British Columbia

The Prespatou area of northeast British Columbia (NEBC) consists almost entirely of natural gas and associated natural gas liquids with annual production of approximately 200 BOE per day for 2018.

As natural gas prices have remained depressed in 2018, the Company has focused on cost minimization and low cost optimizations to maximize profitability in the area. The Company has evaluated the geology of the entire area, in which it holds interests, to assess and identify potential drilling and workover opportunities. The 2019 development plans will focus on continued optimization of production from existing well bores and recompletions of area suspended wellbores. As natural gas prices improve the Company will continue to evaluate its established drilling inventory.

Facilities

The NEBC area production feeds into one of three compressor stations prior to reaching non-operated gas plants for sales. Bonterra has ownership in these operated and non-operated facilities with working interests varying from 0 to 100 percent. Bonterra has operatorship of the compressor station that receives most of its NEBC production. After the gas is gathered and compressed through these gathering systems and compression facilities, it is delivered to either the Spectra Energy gas transmission pipeline for transportation to the McMahon gas plant or the CNRL gas gathering system located east of Fort St. John for treating and processing.

Well Count

The wells in which Bonterra had an interest as at December 31, 2018 that it considers capable of production are set out in the following table:

	Producing Wells				Non-Producing Wells				Total			
	Oil Wells		Gas Wells		Oil Wells		Gas Wells		Oil Wells		Gas Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
AB	1,327	905.7	164	64.4	400	206.2	66	43.4	1,727	1,111.9	230	107.9
BC	-	-	42	21.9	-	-	40	7.6	-	-	82	29.6
SK	89	27.0	-	-	25	4.0	4	4.0	114	31.0	4	4.0
Total	1,416	932.7	206	86.4	425	210.2	110	55.1	1,841	1,142.9	316	141.5

Properties with No Attributable Reserves

Bonterra's properties with no attributable reserves consist of approximately 91,219 gross and 59,776 net undeveloped acres.

None of these land rights require any work commitment and 3,520 gross (2,969 net) acres are subject to expiry in the next twelve months.

The Company is currently reviewing these properties with a focus on maximizing their value.

Risk Management Commodity Contracts

The Company has used various risk management contracts in the past to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided that at least in the near term it will not enter into commodity price agreements, other than small physical delivery contracts for areas with higher operating costs (to avoid voluntarily shutting-in production). These physical delivery contracts amount to less than ten percent of the Company's daily production. The Company will assume full risk with the majority of its production in respect of commodity prices.

Additional Information Concerning Abandonment and Reclamation Costs

In connection with its operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Company budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. The Company estimates such costs through a model that incorporates data from the Company's operating history, industry sources and cost formulas used by Alberta Energy Regulator, together with other operating assumptions. The Company expects all of its net wells to incur these costs. The Company anticipates the total amount of such costs, to be approximately $333,384,000 on an undiscounted basis and $16,128,000 discounted at 10% in accordance with NI 51-101. The calculations of future net revenue associated with proved plus probable reserves under "Oil and Natural Gas Reserves" in this Annual Information Form excludes approximately $219,536,000 on an undiscounted basis and $10,099,000 discounted at 10% as these amounts represent cost for abandonment and reclamation of facilities and wells for which no reserves have been attributed. In the next three years financial years, the Company anticipates that a total of approximately $155,000 on an undiscounted basis and $148,000 discounted at 10% will be incurred in respect of abandonment and reclamation costs.

Tax Horizon

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	7-100	84,491
Share issue costs	20	21
Canadian oil and gas property expenditures	10	93,773
Canadian development expenditures	30	148,573
Canadian exploration expenditures	100	8,063
Federal income tax losses carried forward (1)	100	44,315
Provincial income tax losses carried forward (2)	100	5,898
		385,134

(1) Federal income tax losses carried forward expire in the following years; 2035 - $8,253,000; 2036 - $35,853,000; 2037 - $209,000
(2) Provincial income tax losses carried forward expire in 2036 - $ 5,689,000; 2037 - $209,000

The Company has $8,861,000 (December 31, 2017 - $8,834,000) of investment tax credits that expire in the following years; 2021 - $1,851,000; 2022 - $1,735,000; 2023 - $1,097,000; 2024 - $1,241,000; 2025 - $1,323,000; 2026 - $1,105,000; 2027 - $410,000; and 2035 - $99,000.

The Company has $65,015,000 (December 31, 2016 - $64,435,000) of capital losses carried forward which can only be claimed against taxable capital gains.

Capital Expenditures Incurred

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

($ 000s)	2018	2017
Land	535	738
Acquisitions - proved properties	3,125	4,747 (1)
Disposals	-	(56,752) (1)
Exploration and development costs	75,077	76,956
Net petroleum and natural gas capital expenditures	78,737	25,689

(1) For 2017, includes the Disposition of a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool that closed December 20, 2017 and is effective January 1, 2018. Consideration consisted of $52 million of cash and incremental Cardium assets valued at $4.7 million which is included in capital expenditures.

Exploration and Development Activities

The following tables summarize Bonterra's gross and net drilling activity and success:

	2018					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	34.0	28.0	-	-	34.0	28.0
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	34.0	28.0	-	-	34.0	28.0
Success rate	100%	100%	-	-	100%	100%

	2017					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	38.0	29.6	-	-	38.0	29.6
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	38.0	29.6	-	-	38.0	29.6
Success rate	100%	100%	-	-	100%	100%

Please see discussion under Undeveloped Reserves for important current and likely exploration and development activities.

Production Estimates 2019

	2018			
	Light and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (Bbl/d)	Total (BOE/d)
Alberta[1]	8,607	27,164	1,197	14,331
British Columbia	-	14	1	3
Saskatchewan	126	-	-	126
	8,733	27,178	1,198	14,460

[1] Substantially all of Alberta's production is from the Pembina and Willesden Green fields.

The above production estimates are based on the proved and probable reserve estimates using forecasted prices and costs contained in the Sproule Report.

Production History 2018

Product Type Yearly Quarter	Production Volume per day	Price	Royalties	Production Costs	Netbacks
		Average per Unit of Volume ($/Bbl and $/Mcf)			
Light and Medium Crude Oil (Bbl)					
1 Quarter	8,034	67.78	4.92	18.51	44.35
2 Quarter	8,743	76.51	5.45	15.90	55.16
3 Quarter	7,949	77.20	6.17	21.22	49.81
4 Quarter	7,756	38.96	3.17	18.74	17.05
Conventional Natural Gas (Mcf)					
1 Quarter	24,701	2.24	0.82	1.13	0.29
2 Quarter	25,317	1.16	0.91	1.12	(0.87)
3 Quarter	24,144	1.37	1.03	1.12	(0.78)
4 Quarter	24,045	1.77	0.53	0.99	0.25
Natural Gas Liquids (Bbl)					
1 Quarter	900	38.70	4.92	13.87	19.91
2 Quarter	984	43.69	5.45	14.40	23.84
3 Quarter	1,070	43.95	6.17	15.82	21.96
4 Quarter	1,025	34.73	3.17	12.60	18.96

The following table provides a summary of the average production volumes from Bonterra's producing areas.

	2018		
	Light and Medium Crude Oil and NGL (Bbl per day)	Conventional Natural Gas (Mcf per day)	Total (BOE per day)
Alberta	8,949	23,338	12,839
Saskatchewan	159	47	167
British Columbia	6	1,165	200
	9,114	24,550	13,206

Lease Holdings

Bonterra's holdings of petroleum and natural gas leases and rights are as follows:

	2018		2017	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	339,019	208,086	313,909	192,945
Saskatchewan	8,178	5,691	8,178	5,647
British Columbia	62,045	23,478	62,045	22,594
	409,242	237,255	384,132	221,186

INFORMATION RESPECTING BONTERRA ENERGY CORP.

Operations of Bonterra Energy Corp.

Management Policies and Acquisition Strategy

The objectives of the management of Bonterra are to maximize total return to shareholders over the long-term by growing production and maintaining and enhancing cash dividends to shareholders. These objectives are met through the optimum utilization and development of existing crude oil and natural gas properties and acquisition or development of new producing or undeveloped properties.

Bonterra selectively acquires producing and non-producing oil and natural gas properties with exploration, development or operational enhancement opportunities. The development and exploration opportunities acquired are generally of a low risk nature. Where higher risk oil and gas prospects are acquired as part of a package of properties, Bonterra may sell, farm out or develop the exploration prospects, depending on management's assessment of the prospects' potential, costs involved and Bonterra's own technical expertise.

Dividends

Shareholders of record on a dividend record date, currently established by Bonterra to be on or about the 15th of each calendar month, will be entitled to receive dividends which are paid by Bonterra to those shareholders on the corresponding dividend payment date, generally on the last day of each calendar month.

See "Dividends to Shareholders" for the past cash dividends made or declared to shareholders of Bonterra.

Environmental Obligations

Bonterra emphasizes the importance of creating and maintaining a safe and environmentally sound operation. The Company focuses on having management involvement in establishing safety policies, proper training of field operators, continuous and thorough review of operating procedures and policies conducted by the field operation's staff and management and by monitoring and ensuring compliance with safety and environmental regulations.

Acquisition Due Diligence

Bonterra conducts due diligence on all prospective acquisitions. Site inspections and file reviews are conducted by an internal team. Potential contamination and operational issues are identified at this stage to help protect Bonterra from purchasing properties with significant environmental liabilities.

Spill and Incident Control

Bonterra field operators and staff are required to report all spills, incidents and near misses to the management of Bonterra for review and to the regulatory agency when required. The investigation of all such incidents allows Bonterra, including management, to determine the factors responsible and assist in the identification of other similar situations prior to incidents occurring and ensuring proper actions are taken. Overall, Bonterra is confident that the program will reduce the occurrence of spills and assist in reducing future losses.

Insurance

Bonterra carries insurance coverage to protect its assets. Insurance coverage is subject to policy limitations and deductibles. Coverage is determined and placed by Bonterra subsequent to giving consideration to the perceived risk of loss, limit of coverage determined appropriate and the cost of coverage. Coverage currently in place includes protection against third party liability and pollution, property damage or loss and business interruption.

Borrowing

The Company's debt obligations consist of a bank facility, a subordinated promissory note and borrowing from a related party. Details of the banking arrangement is contained in Note 13 of Bonterra's audited annual financial statements for the year ended December 31, 2018, contained in the Company's 2018 Annual Report. The financial statements and management discussion and analysis are incorporated herein for reference.

Personnel

At the date of this report, Bonterra employed a total of 38 persons and contracted numerous office and field operations personnel.

INDUSTRY CONDITIONS

Production and Operation Regulations

The oil and natural gas industry is subject to extensive controls, laws and regulations imposed by various levels of government. These laws and regulations may be changed in response to economic or political conditions, and regulate among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations. While it is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas corporations of similar size, the controls and regulations should be considered carefully by investors. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Western Canada.

Pricing and Marketing of Oil and Natural Gas

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which mean that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand; however, regional market and transportation issues also influence prices. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms.

Negotiation 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.

The pricing of condensates and other NGL such as ethane, butane, propane and pentane plus 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 NGL, 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

Crude oil, natural gas and NGLs exports from Canada are subject to the National Energy Board Act (Canada) (the "NEB Act") and the National Energy Board Act Part VI (Oil and Gas) Regulation (the "Part VI Regulation"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "NEB") is required. There is no longer public hearing requirement for the export of natural gas and NGLs. Instead, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("Cabinet").

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from 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. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("CER"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

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 are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. 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, Pipeline Capacity and Market Access

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 areas 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. Although the current federal government introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition creates further uncertainty. In addition, export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian 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, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many 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 Expansion from Hardisty, Alberta, to Superior, Wisconsin, has an expected in-service date in the latter half of 2020.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the Federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction 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. Following the Court's direction, the Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision. On February 22, 2019, the NEB decided the Trans Mountain Pipeline expansion project was in the best interests of Canadians and should go forward subject to 156 conditions. The NEB also made 16 new recommendations to the Governor in Council. Cabinet will have three months to consider the NEB's report and, subject to a new round of indigenous consultation, decide whether it will approve or deny the pipeline expansion.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGLs products from British Columbia's north coast. See "*Regulatory Authorities and Environmental Regulation*" in these Industry Conditions.

On November 28, 2018, the Government of Alberta announced that Alberta has started negotiations for investment in new rail capacity to address the historically high price differential. Commencing in late 2019, the Government of Alberta intends to create enough new rail capacity to move 120,000 barrels a day out of the province. The Government expects that the railcar acquisition will narrow the oil price gap by up to $4 per barrel and will provide junior producers with a more affordable option to move their oil to market.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate an 8.7% short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, the Government of Alberta will, on a monthly basis, direct oil producers producing more than 10,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators' subject to a curtailment order. The first curtailment order took effect on January 1, 2019. The Government expects that the 8.7% curtailment rate will gradually drop over the course of 2019. Currently the Company is not subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-United States Free Trade Agreement. 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. In the context of energy resources, Canada continues to remain 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. NAFTA parties are generally prohibited from imposing minimum or maximum import and export price restrictions. However, import price restrictions are allowed to the extent that such restrictions are allowed by the anti-dumping and anti-subsidy provisions of the *General Agreement on Tariffs and Trade*.

On November 30, 2018, US President Donald Trump, Prime Minister Trudeau, and outgoing Mexican President Enrique Pena Nieto signed an authorization for a new trade deal that will replace NAFTA, referred to as the United States-Mexico-Canada Agreement ("USMCA"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the United States it is unclear when the end of the NAFTA era will be. As the United States remains by far Canada's largest trade 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 the Company's business.

As discussed above, in December 2018 the Government of Alberta announced a curtailment of Alberta's crude oil and crude bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduces the required offering under NAFTA, with the result that the amount of oil and bitumen that Canada is required to offer, while Canadian oil is at depressed prices, may be reduced. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

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.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft 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. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

Rights are granted to energy companies to explore for and produce oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Lease terms vary in length, for oil and natural gas leases usually from two to five years and for Alberta bitumen leases usually 15 years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Lands in an oil and natural gas lease are continued beyond their primary term by drilling a well(s). A lease is proven productive at the end of its primary term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease. The tenure only comes to an end when the holder can no longer prove its agreement is capable of producing oil or gas.

Many jurisdictions in Canada, including the provinces of Alberta and Saskatchewan have legislation in place for mineral rights reversion to the Crown where stratigraphic formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for nonproducing lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas can also be privately owned (freehold) and rights to explore for and produce such oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low to encourage exploration and development activity. Additional 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.

In addition, the Federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the Federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The Federal government also announced in late 2018 that it will make $1.6 billion available to the oil and gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for oil and gas projects related to economic diversification as well as direct funding for clean growth oil and gas projects.

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 - Royalties

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes; to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 29, 2016, the Government of Alberta release and accepted the Royalty Review Advisory Panel’s recommendations, which outlined the implementation of Modernized Royalty Framework for Alberta (MRF). The MRF formally took effect on January 1, 2017 for new wells drilled after this date. 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. On July 12, 2016, the Government of Alberta announced that producers could apply for early adoption of the MRF in respect of wells spud between July 13, 2016 and December 31, 2016.

The MRF 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 MRF is 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 horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator ("AER") on an annual basis.

Producers pay a flat royalty rate of 5 percent 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 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 as the mature well's production declines.

As the MRF 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.

The Old Framework is applicable to all conventional 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 oil production under the Old Framework range from a base rate of 0% to a cap of 40%. 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. 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%. Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

Alberta - Incentive Programs

Under the MRF, two strategic programs have been recently introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The new Enhanced Hydrocarbon Recovery Program (the "EHR Program") began January 1, 2017 and replaced the existing EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by water flooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of five per cent on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the MRF.

The new Emerging Resources Program (the "ERP") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of five per cent until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard drilling and completion cost allowance under the MRF in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the MRF.

Saskatchewan - Royalties

The amount payable as a royalty with respect to oil depends on the type and vintage of the oil, the quality of the oil produced in the month and the value of the oil determined monthly by the provincial government. Each month, royalty rates are adjusted based on reference prices established by the Province for each type of oil. There are separate reference prices established for each type of oil (heavy oil, Southwest designated oil, or non-heavy oil other than Southwest designated oil) which represents the average well head price received by producers during the month for sales of that oil type in Saskatchewan.

The government of Saskatchewan has introduced the Oil and Gas Orphan Fund, funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

Saskatchewan - Incentive Programs

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

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

British Columbia - Royalties

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will thus vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare depending on the total number of hectares owned by the entity.

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.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

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

Bonterra has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which the Company operates. The Company employs an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although the Company maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines. The Canadian Environmental Protection Act, 1999 and the Canadian Environmental Assessment Act, 2012 provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("CER"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "Agency") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effect of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced Bill C-48, the Oil Tanker Moratorium Act, 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 is still considering the bill, which passed third reading on May 8, 2018. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the Responsible Energy Development Act and a number of related Acts 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 Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

Saskatchewan

The Saskatchewan Ministry of the Economy, Petroleum Branch, is the primary regulator of crude oil and natural gas activities in the province. In May 2011, the Government of Saskatchewan passed changes to The Oil and Gas Conservation Act (the "SKOGCA"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of The Oil and Gas Conservation Regulations, 2012 (the "OGCR") and The Petroleum Registry and Electronic Documents Regulations (the "Registry Regulations"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

British Columbia

In British Columbia, the Oil and Gas Activities Act (the "OGAA") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "B.C. Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The Environmental Protection and Management Regulation establish the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the B.C. Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the Petroleum and Natural Gas Act, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The British Columbia Government recently passed Bill 51 – 2018: Environmental Assessment Act, which replaces the environmental assessment regime that has been in place since 2002. The Government expects that the updated Environmental Assessment Act will enter into force in late 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process, as well as enhance indigenous engagement in the project approval process with an emphasis on consensus-building.

Liability Management Rating Programs

Alberta

The AER administers the licensee Liability Management Rating Program (the "AB LMR Program"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "AB LLR Program"), the Oilfield Waste Liability Program (the "AB OWL Program") and the Large Facility Liability Management Program (the "AB LFP"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. 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 licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("LMR"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. 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.

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 ("WIP") becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In Redwater Energy Corporation (Re) ("Redwater"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal Bankruptcy and Insolvency Act (the "BIA"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the

Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing 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 pending a final decision from the Supreme Court of Canada. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence 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 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. While the Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

The AER has also implemented the Inactive Well Compliance Program (the "IWCP") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP completed its third year on March 31, 2018 but the AER has not yet released its third annual report.

Saskatchewan

The Ministry of the Economy administrates the Licensee Liability Rating Program (the "SK LLR Program"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "Oil and Gas Orphan Fund") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR of below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LMR calculation in evaluating deposit requirements, and that further changes may be forthcoming.

British Columbia

Similar to Alberta, the B.C. Commission oversees a Liability Management Rating Program (the "BC LMR Program"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the B.C. Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In the spring of 2018 the Government of British Columbia passed certain amendments to the OGAA (the "Amendments") which when brought into force, will replace the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("OSRF"). Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders currently make monthly payments of $0.03 per 1,000 cubic metres of marketable gas produced and $0.06 per cubic meter of petroleum produced. The Amendments will require permit holders to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The Amendments permit the B.C. Commission to impose more than one levy in a given calendar year. It is not clear when these provisions of the Amendments changing from a tax based on production to a liability-based payment will be brought into force.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "Framework"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply 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 in 2018. Seven provinces and territories have introduced carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it will take effect in the Yukon, and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

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, but will not come into force until 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 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.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Alberta government has announced it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds. 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.

The *Carbon Competitiveness Incentives Regulation* (the "CCIR"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "MRGGA") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target. British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to $35/tonne in April 2018.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "GGIRCA") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of oil and gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. On January 16, 2019, the B.C. Commission announced a series of amendments to the B.C. *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules will come into effect on January 1, 2020.

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

The following are certain risk factors relating to the business of Bonterra which prospective investors should carefully consider before deciding whether to purchase shares. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally.

Commodity Prices and Foreign Exchange Rates

Bonterra's results of operations and financial condition are dependent on the prices received for their oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, availability of infrastructure and pipelines, as well as conditions in other oil producing regions, which are beyond the control of Bonterra. Any decline in oil and natural gas prices could have a material adverse effect on Bonterra's operations, financial condition, the value of the Company's reserves and the level of expenditures for the development of its oil and natural gas reserves. World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact Bonterra's net production revenue. The management of Bonterra may manage the risk associated with changes in commodity prices and foreign exchange rates by causing Bonterra to, from time to time, enter into oil or natural gas price hedges and foreign exchange contracts. To the extent that Bonterra engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to credit risks associated with counterparties with which it contracts. The Company has assumed the risk in respect of commodity prices, except for a small portion of physical delivery sales contracts to manage commodity risk on the Company's higher operating cost areas.

Bonterra conducts an annual assessment of the carrying value of its assets in accordance with International Financial Reporting Standards. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Company's assets may be subject to impairment.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Company may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Insurance Risks*" in these Risk Factors. In either event, the Company could incur significant costs.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. 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 the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to obtain the necessary approvals to build pipelines and other facilities to provide the oil and gas industry in Western Canada better access to markets has led to additional uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company’s reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Company’s cash flow which could result in a reduced capital expenditure budget. As a result, the Company may not be able to replace its production with additional reserves and both the Company’s production and reserves could be reduced on a year over year basis. A prolonged period of adverse market conditions may impede the Company’s ability to refinance its Credit Facility or arrange alternative financing when the Credit Facility becomes due or if the lending limits under the Credit Facility are reduced upon periodic review. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Bonterra’s cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations.

Title to and Right to Produce from Assets

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

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

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to Bonterra's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Bonterra or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*". In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. As such, the price at which the common shares of the Company will trade cannot be accurately predicted.

Regulatory Approvals

In order to conduct its oil and natural gas operations, the Company requires regulatory approvals from various government authorities. There can be no assurance that Bonterra will be able obtain or renew all of the regulatory approvals that may be required to conduct operations that it may wish to undertake or that it will obtain such equipment and terms and conditions acceptable to Bonterra.

Surface Conditions

The exploration for and development of oil and natural gas reserves depends upon access to areas where operations are to be conducted. Oil and gas industry operations are affected by road bans imposed from time to time during the winter break-up and thaw period in the spring. Road bans are also imposed due to snow, mud and rock slides and periods of high water or wild fires which can restrict access to Bonterra's well sites and production facilities.

Bonterra conducts a portion of its operations in areas accessible only on a seasonal basis. Unless the surface is sufficiently frozen, Bonterra is unable to access its properties, drill or otherwise conduct its operations as planned. In addition, if the surface thaws earlier than expected, Bonterra must cease its operations for the season earlier than planned. Limitations on Bonterra's ability to access properties or conduct its operations as planned could result in a shut down or slowdown of its operations, which may adversely affect its business.

Operating and Capital Costs

The Company's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality standards and supply chain disruptions. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact Bonterra's business, financial condition, results of operations, cash flows and value of it oil and gas reserves.

Hydraulic Fracturing

Bonterra utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated completion fluids and other technologies in connection with its drilling and completion activities. Public concern over the hydraulic fracturing process has raised questions regarding the completion fluids used in the fracturing process, their effect on fresh water aquifers and surface waterbodies, the use and disposal of water in connection with completion operations and the ability of such water to be recycled. Certain government and regulatory agencies in Canada and the United States have been investigating the potential risks associated with the hydraulic fracturing process. Bonterra is unable to predict the impact of any potential regulations upon the oil and gas industry and the impact to Bonterra's business. The implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase Bonterra's costs of compliance, operating costs, the risk of litigation and environmental liabilities or negatively impact Bonterra's prospects, any of which may have a material adverse effect on our future business, financial condition and results of operations.

Alberta

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how B.C.'s regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. Despite a timeline to fulfill its mandate by December 31, 2018, the panel's findings are not yet publically available. Therefore, it is unclear how the panel's recommendations will influence the regulatory regime currently in place in B.C. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Company's business operation, financial condition, results of operations and prospects.

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation ("Kiskatinaw") area, in May 2018, the British Columbia Oil & Gas Commission (the "B.C. Commission") issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the B.C. Commission, and the suspension of operations if a seismic event above a 3.0 magnitude occurs. In November 2018, seismic activity near Fort St. John in the Kiskatinaw area resulted in the suspension of several companies' operations, demonstrating the B.C. Commission's willingness to enforce these enhanced regulatory requirements. The B.C. Commission continues to monitor seismic events across the province and may implement similar requirements in other areas if necessary.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern B.C. have been constructed without the requisite regulatory authorization. While the B.C. Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Company may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Company is not strictly complying with the current regulatory framework.

Disposal of Fluids Used in Operations

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

Shallow Rights Reversion

As part of Alberta's New Royalty Framework announced on October 25, 2007, Alberta Energy introduced Shallow Rights Reversion ("SRR") for Alberta Crown petroleum and natural gas agreements ("P&NG Agreements") pursuant to which mineral rights in all zones above the shallowest producing zone within affected P&NG Agreements would revert to the Crown. SRR would apply to P&NG Agreements purchased after January 1, 2009 and in addition, commencing April 2011, Alberta Energy was to begin issuing notices ("SRR Notices") for P&NG Agreements purchase prior to January 2009 that had been continued for an indefinite term. Alberta Energy since announced its intention to place an indefinite hold on serving SRR Notices with respect to pre-January 1 2009 P&NG Agreements. However this decision does not affect P&NG Agreements issued after January 1, 2009 as these agreements remain subject to SRR upon expiry, beginning in 2014. Bonterra allocates funds within its annual capital expenditure budget toward proving productivity and retaining as much of its acreage as possible. However SRR could result in some of Bonterra's shallow acreage reverting to the Crown. SRR is not specific to Bonterra and will affect the industry in Alberta generally.

Legal Proceedings

Bonterra may from time to time be subject to litigation and regulatory proceedings arising in the normal course of its business. Bonterra cannot determine whether such litigation and regulatory proceedings will, individually or collectively, have a material adverse effect on its business, results or operations and financial condition. To the extent expenses incurred in connection with litigation or any potential regulatory proceeding or action (which may include substantial fees of attorneys and other professional advisors and potential obligations to indemnify officers and directors who may be parties to such actions) are not covered by available insurance, such expenses could adversely affect Bonterra's cash position.

Third Party Credit Risk

Bonterra may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on Bonterra and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Bonterra's ongoing capital program, potentially delaying the program and the results of such program until it finds a suitable alternative partner.

Numerous applications have been filed with regulatory bodies within Canada and the U.S. to build or expand existing pipeline infrastructure to transport crude oil and natural gas to markets. If the projects are not approved it may impact our ability to ship our products to sales markets, which could have a material adverse effect on production levels or on the prices that we receive for our production.

Operational Dependence

Other companies operate some of the assets in which Bonterra has an interest. As a result, Bonterra will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect its financial performance. Bonterra's return on assets operated by others will therefore depend upon a number of factors that may be outside of its 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.

Access to Capital

The Company will have to incur substantial capital expenditures in the future in order to carry out its oil and natural gas exploration and development activities. While there are various financing forms available to the Company, including the issuance of new equity or debt, asset sales, joint ventures or other alternatives, the Company's ability to arrange such financings or other satisfactory arrangements in the future may depend in part upon the prevailing capital market conditions, as well as the Company's business performance. These factors could negatively impact the Company in terms of its ability to raise additional capital, as well as increased volatility in oil and gas prices which could affect revenues and cash flows and Company valuations.

Capital Investment

The timing and amount of capital expenditures will directly affect the amount of income for payment of dividends to shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, the ability of Bonterra to make necessary capital investments to maintain or expand its oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Bonterra is required to use cash flow from operations to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of dividends will be reduced.

General Economic Conditions, Business Environment

The business of the Company is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil and natural gas, revenues, operating costs, access to capital, timing and extent of capital expenditures, credit risk and counter party risk. There can be no assurance that any risk management steps taken by the Company, with the objective of the mitigating the foregoing risks, will avoid future loss due to the occurrence of such risks.

Credit Facility Arrangements

Bonterra has secured credit facilities. Variations in interest rates and scheduled principal repayments, if required under the terms of the banking agreements, could result in significant changes in the amount of working capital required to be applied to debt service. Although it is believed that the bank lines of credit are sufficient there can be no assurance that the amount will be adequate for the financial obligations of Bonterra or that additional funds can be obtained.

In addition, the maximum amount we are permitted to borrow is subject to periodic review by the lenders, typically semi-annually. The Company’s lenders generally review the Company’s oil and gas production and reserves, forecast prices, business environment and other factors to establish the amount we can borrow. In the event the lenders decide to reduce the amount of credit available, the Company may be required to repay all or a portion of the amounts owing.

Interest Rates

The Company may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase Bonterra’s net interest expense and negatively impact its financial results.

Delay in Cash Payments

In addition to the usual delays in payment by the purchasers of oil and natural gas to the operators of Bonterra's properties, and by the operator to Bonterra, 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, blow-outs or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

Reserves Estimates

Although Sproule has prepared Bonterra's reserve figures using methods of estimating reserves consistent with those commonly followed in the industry and believe that those methods 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. Probable reserves estimated for properties may require revisions based on the actual development strategies employed to prove such reserves. Estimated reserves may also be affected by changes in oil and natural gas prices. Declines in the reserves of Bonterra which are not offset by the acquisition or development of additional reserves may reduce the underlying value of the common shares to shareholders.

The reserve report under the heading "Operational Information – Disclosure of Reserve Data" has been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, NGLs and natural gas are realized by Bonterra and substituted for the price assumptions utilized in the reserve report, the present value of estimated future net cash flows for Bonterra's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions.

Expiration of Licenses and Leases

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company may realize less on disposition than their carrying value on the financial statements of the Company.

Investment Eligibility

Bonterra common shares are qualified investments for RRSPs, RRIFs, RESPs and DPSPs (collectively "Exempt Plans"). Where at the end of any month an Exempt Plan holds common shares that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the *Income Tax Act* (Canada) equal to one percent of the fair market value of the common shares at the time those common shares were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP or RRIF holds common shares that are not qualified investments, the trust will become taxable on its income attributable to the common shares while they are not qualified investments. Where a trust governed by an RRSP or RRIF acquires common shares that are not qualified investments, the fair market value of the investment will be included in the income of the annuitant for the year of the acquisition. RESPs which hold common shares that are not qualified investments may have their registration revoked by the Canada Revenue Agency.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of Bonterra or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Bonterra, and there can be no assurance that Bonterra will be able to satisfy its actual future environmental and reclamation obligations.

Actual asset retirement costs incurred in the ordinary course in a specific period will reduce the amount of cash available for payment of dividends to shareholders.

Abandonment and Reclamation Costs

The Company is required to abandon and reclaim all of its projects at the end of their economic life. These costs will be substantial. The estimate for abandonment and reclamation costs are based on a number of sources including guidelines from provincial regulatory groups, historical data from operations and management's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

Recently as a result of the prolonged downturn in the oil and gas industry the number of orphan wells (wells owned by insolvent parties) has increased. The cost of abandoning orphan wells has largely been funded by industry. Accordingly, the increase in the number of orphan wells could result in an increase in fees or assessments to other oil and gas producers, such as Bonterra, to fund the abandonment and reclamation of these orphan wells.

Carbon Pricing Risk

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

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has begun taking steps to implement certain of its promises made during the campaign. The administration has withdrawn the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, the North American Free Trade Agreement ("NAFTA") has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the Canada-United States –Mexico Agreement which will replace NAFTA once ratified by the three signatory countries. 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 the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Company.

Climate Change Regulations

The Company's exploration and production facilities and other operations and activities emit greenhouse gases ("GHG") which may require the Company to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. The federal carbon levy goes into effect on April 1, 2019 and will affect provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Ontario, Manitoba, Saskatchewan and New Brunswick. The federal carbon levy will be at an initial rate of $20 per tonne. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The implementation of the federal carbon levy is currently subject to a constitutional challenge submitted by the Province of Saskatchewan, which is supported by the Provinces of Ontario and New Brunswick. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

In addition, there has been public discussion that climate change may be associated with extreme weather conditions and increased volatility in seasonal temperatures. Extreme weather could interfere with the Company's production and increase the Company's costs. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

Royalty Regimes

There can be no assurance that the proposed MRF by the government of Alberta and potential changes by the federal or Saskatchewan governments may not occur that will make the Company’s properties uneconomic. An increase in royalties would reduce the Company’s earnings and cash flow and could make future capital investments or the Company’s operations uneconomic.

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. Losing the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key personnel insurance in effect**.** The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Human Resources

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

Management of Growth

The Company may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. If the Company is unable to deal with this growth, it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Company's deemed assets to deemed liabilities or other changes to the requirements of liability management programs, may result in significant increases to the Company's compliance obligations. In addition, the liability management regime may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The Alberta Court of Queen's Bench 2016 decision, *Redwater Energy Corporation (Re)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Issuance of Debt

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

Information Technology Systems and Cyber-security

The Company has 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. The Company depends 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, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's 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 the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's 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 the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's 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. The Company applies technical and process controls in line with industry-accepted standards to protect its 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 the Company's 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 the Company’s business, financial condition and results of operations.

Social Media

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Company's systems and obtain confidential information. The Company restricts the social media access of its employees and periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Dividends

Payment of dividends from crude oil and natural gas production (without commodity price increases or cost effective acquisition and development activities) could be reduced in a manner consistent with declining commodity prices or declining production from typical oil, natural gas and NGL reserves.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the Canada – United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

Reputational Risk Associated with the Company's Operations

The Company's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of the Company's 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 the Company operates 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. The Company's 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 the Company has no control. In particular, the Company's reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property caused by the Company's operations, or due to opposition from special interest groups opposed to oil and natural gas development. In addition, if the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business.

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 the Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and 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 the Board, management and employees of the Company. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Company, or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities even if the Company's 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 the Company's asset which may result in an impairment change.

Dilution

The Board may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Company issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Common Shares could decline.

Depletion of Reserves

Bonterra has certain unique attributes which may differentiate it from other oil and gas industry participants. Bonterra will not be reinvesting cash flow in the same manner as other industry participants. Bonterra has a long reserve life index and its decline rate is lower than many other industry participants. Bonterra will be retaining a portion of its cash flow for reinvestment purposes, but the retained amount may be less than other industry participants and could result in decreases in production levels and reserves.

The future oil and natural gas reserves and production of Bonterra, and therefore its cash flows, will be highly dependent on its success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Bonterra's reserves and production will decline over time as reserves are exploited.

There can be no assurance that Bonterra will be successful in developing or acquiring additional reserves on terms that meet Bonterra's investment objectives.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Bonterra will actively compete for capital, skilled personnel, undeveloped lands, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Bonterra. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Aboriginal Claims

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

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's 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, the Company 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 its business that such a breach of confidentiality may cause.

Net Asset Value

The net asset value of Bonterra’s assets from time to time will vary dependent upon a number of factors beyond the control of management, including oil, natural gas and NGL prices. The trading price of Bonterra’s common shares from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be less than the net asset value of Bonterra’s assets.

Potential Conflicts of Interest

There may be circumstances in which the interests of entities managed by Bonterra will conflict with those of Bonterra and its shareholders. Companies managed by Bonterra may acquire oil and natural gas properties or entities on their behalf and Bonterra may manage and administer those additional properties or entities, as well as enter into other types of energy related management, advisory and investment activities.

In the event of such conflicts, decisions will be made on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties consistent with the duties of Bonterra to each group of persons. Bonterra will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Bonterra and other interested parties fairly taking into account all of the circumstances of Bonterra and such interested party and to act honestly and in good faith in resolving such matters.

Circumstances may also arise where members of the Board of Directors of Bonterra are directors or officers of corporations or other entities involved in the oil and natural gas industry which are in competition with the interests of Bonterra. No assurances can be given that opportunities identified by such board members will be provided to Bonterra.

Management Estimates and Assumptions

In preparing consolidated financial statements estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock-based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

Insurance Risks

The Company's property and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Company.

Geo-Political Risks

The long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. The possibility that infrastructure and other facilities, such as pipelines, terminals and refineries, may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks have resulted in, and are expected to continue to result in, increased costs to the Company's business. Furthermore, any interruption in the services provided by infrastructure on which the Company relies as a result of terrorist attack would have a material adverse effect on the Company's results of operations, financial condition and prospects.

Non-Governmental Organizations and Eco-Terrorism Risks

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

In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have insurance to protect against the risk from terrorism.

Global Financial Markets

The market events and conditions that transpired in recent years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the Organization of the Petroleum Exporting Countries, the ongoing risks facing the North American and global economies and increased supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays.

The Imposition of a "Cross-Border" Tax

U.S. legislators are considering the adoption of a border adjustment tax which, if adopted, would reduce or eliminate the cost U.S. companies can deduct from revenues for importing goods, including the importation of oil and gas. The impact of such a tax on the Company cannot be predicted, however, such impacts could be negative and could have a material adverse effect on the Company’s business and financial results.

Changes in Legislation and Canadian Tax Considerations

There can be no assurances that income tax laws and government incentive programs relating to the oil and natural gas industry will not be changed in a manner which adversely affects Bonterra and its shareholders. There can be no assurance that the Canada Revenue Agency will agree with how Bonterra calculates its income for tax purposes or that the Canada Revenue Agency will not change its administrative practices to the detriment of Bonterra or its shareholders.

As Bonterra is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. Bonterra has reviewed its historical income tax returns with respect to the characterization of the costs incurred in the oil and natural gas business as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. Bonterra has filed or will file all required income tax returns and believes that it is full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material. No current taxes owed for the 2017 fiscal year.

Internal Controls Over Financial Reporting

Internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 (NI 52-109), includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;
2. Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that

receipts and expenditures of Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and

3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The Company has designed and implemented ICFR as defined in NI 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013).

It should be noted that while the Company's believes its internal controls and procedures provide a reasonable level of assurance and are effective; they do not expect that these controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that its objectives are met.

Cost of New Technologies

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

Availability of Equipment and Qualified Personnel and Related Costs

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Bonterra and may delay Bonterra's exploration and development activities. In addition, the costs of qualified personnel and equipment in the areas where Bonterra's assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment in such areas.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; 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; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; 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.

These factors could result in Bonterra being unable to execute projects on time, on budget, or at all and may be unable to effectively market its oil and natural gas products.

Seasonality and Climate

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Bonterra.

Alternatives to, and Changing Demand for, Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Bonterra cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Waterflood

The Company undertakes or intends to 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 the Company needs 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 the Company 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 the Company is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's results of operations.

Limited Ability of Residents in the United States to Enforce Civil Remedies

The Company is a corporation formed pursuant to the provisions of the Canada Business Corporations Act and has its principal place of business in Alberta, Canada. All of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of 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 judgments 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 the Company or against 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 judgments 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Company delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. Notwithstanding the Alberta government's plans to purchase approximately 7,000 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions - Transportation Constraints and Market Access* ". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. As a result, producers are increasingly turning to rail lines as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, operations and cash flows. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing for receipt of approvals of major projects remains unclear.

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

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Company's ability to process its 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.

Forward-Looking Information May Prove Inaccurate

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The financial statements and the management's discussion and analysis of its financial condition and results of operations for the year ended December 31, 2018, as contained in the Company's Annual Report for the year ended December 31, 2018 is incorporated by reference in this Annual Information Form.

DIVIDENDS TO SHAREHOLDERS

Cash Dividend Policy

Shareholders of record on a dividend record date are entitled to receive dividends which are paid by Bonterra to its shareholders on the corresponding dividend payment date. Bonterra has established that the dividend record date will be on or about the 15^{th} day of each calendar month with the last day of each month being the corresponding payable date.

The following cash dividends were paid by Bonterra since 2016:

Month of Record and Payment Date	Amount per Share
January 2016	$0.10
February 2016	$0.10
March 2016	$0.10
April 2016	$0.10
May 2016	$0.10
June 2016	$0.10
July 2016	$0.10
August 2016	$0.10
September 2016	$0.10
October 2016	$0.10
November 2016	$0.10
December 2016	$0.10
January 2017	$0.10
February 2017	$0.10
March 2017	$0.10
April 2017	$0.10
May 2017	$0.10
June 2017	$0.10
July 2017	$0.10
August 2017	$0.10
September 2017	$0.10
October 2017	$0.10
November 2017	$0.10
December 2017	$0.10
January 2018	$0.10
February 2018	$0.10
March 2018	$0.10
April 2018	$0.10
May 2018	$0.10
June 2018	$0.10
July 2018	$0.10
August 2018	$0.10
September 2018	$0.10
October 2018	$0.10
November 2018	$0.10
December 2018	$0.01
January 2019	$0.01
February 2019	$0.01
March 2019	$0.01

The historical dividend payments described above may not be reflective of future dividend payments, which will be subject to review by the Board of Directors taking into account the prevailing financial circumstances of Bonterra at the relevant time. See "Risk Factors".

CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Transactions during the years 2018 and 2017 in the shares of the common stock of the Company are as follows:

	December 31, 2018		December 31, 2017	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**33,310,796**	**763,977**	33,302,435	763,788
Issued pursuant to the Company share option plan	**78,000**	**1,143**	8,361	143
Transfer from contributed surplus to share capital		**156**		46
Balance, end of year	**33,388,796**	**765,276**	33,310,796	763,977

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The Company provides an equity settled stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,338,880 (December 31, 2017 – 3,331,080) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2018 and December 31, 2017, and changes during the years ended on those dates is presented below:

	Number of options	**Weighted average exercise price**
At January 1, 2017	2,737,000	$30.50
Options granted	1,936,000	14.91
Options exercised (1)	(14,000)	20.46
Options forfeited	(256,000)	23.03
Options expired	(1,597,000)	32.25
At December 31, 2017	2,806,000	$19.48
Options granted	1,073,000	6.39
Options exercised	(78,000)	14.67
Options forfeited	(53,000)	19.01
Options expired	(954,000)	28.23
At December 31, 2018	2,794,000	$11.62

(1) 7,000 options were exercised under the cashless option method, which resulted in 1,361 shares being issued in which the Company received no proceeds.

The following table summarizes information about options outstanding at December 31, 2018:

	Options Outstanding				Options Exercisable	
Range of exercise prices	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price		Number exercisable	Weighted-average exercise price
$ 5.00 - $ 10.00	1,031,000	2.1 years	$	5.93	-	$ -
10.01-20.00	1,731,000	1.3 years		14.74	30,000	14.56
20.01-35.00	32,000	0.9 years		25.93	16,000	27.95
$ 5.00 - $ 35.00	2,794,000	1.6 years	$	11.62	46,000	$ 14.83

MARKET FOR SECURITIES

The outstanding shares are listed and posted for trading on the Toronto Stock Exchange (TSX) under the trading symbol BNE. The following table sets forth the high and low trading prices and the aggregate volume of trading of the shares and trust units as reported by the TSX for the periods indicated.

Month	Price Range	Volume
January 2018	$13.70 - $15.84	3,610,000
February 2018	$12.26 - $14.65	2,599,900
March 2018	$12.58 - $14.19	2,421,400
April 2018	$12.66 - $16.14	3,215,100
May 2018	$15.53 - $17.59	3,229,800
June 2018	$15.67 - $17.54	1,649,100
July 2018	$17.03 - $18.99	1,430,000
August 2018	$17.83 - $20.29	2,383,100
September 2018	$17.44 - $19.48	1,843,900
October 2018	$14.30 - $19.86	2,905,800
November 2018	$6.86 - $15.03	8,576,900
December 2018	$5.31 - $8.42	7,659,500

On December 31, 2018, the closing price of Bonterra shares on the TSX was $6.46 (December 31, 2017 - $15.30).

The Company as of December 31, 2018 had 33,388,796 shares outstanding.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the directors and executive officers of Bonterra, none of the securities of Bonterra are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND OFFICERS

All directors of Bonterra are elected by its shareholders at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed. All officers are appointed by the Board of Directors. The name, municipality of residence, principal occupation for the past five years and year of appointment as a director or commencement of employment for officers of Bonterra are set forth as follows:

Name and Municipality of Residence	Position Since	Principal Occupation for Past Five Years
Brad A. Curtis Calgary, AB	Senior Vice President, Business Development March, 2017	B. Com., B.Sc., P.Geo, Mr. Curtis has been Vice President, Business Development since February 2012 and has held various positions with Bonterra since 2005.
Gary J. Drummond(3)(4) Regina, SK	Director August, 1999	B.A., LLB., Mr. Drummond is a private investor and a director of Pine Cliff Energy Ltd.
George F. Fink(3)(4) Calgary, AB	CEO, Director and Chairman January, 1981	B.Com., C.A., Executive Chairman of the Board of Pine Cliff Energy Ltd.

Randy M. Jarock[1][2] Calgary, AB	Director, June, 2012	B.Sc. (Engineering), formally President and COO of Bonterra since 2008 and prior thereto its Chief Operating Officer since 2005 and has been employed by the Company since 1998. Mr. Jarock is also a director of Pine Cliff Energy Ltd.
Adrian Neumann Calgary, AB	Chief Operating Officer, July, 2013	B.Sc., P.Eng., Mr. Neumann joined Bonterra as Vice President, Engineering and Operations in June, 2012.
Robb D. Thompson[4] Calgary, AB	CFO & Corporate Secretary February 2011	B.Com., C.A., Mr. Thompson has been CFO and Corporate Secretary since February 2011.
Dan Reuter[1][3][4] San Francisco, CA	Director August 2018	Managing Director of Oberndorf Enterprises, a San Francisco based private fund, holding a significant investment in Bonterra.
Rodger A. Tourigny[1][2] Calgary, AB	Director May, 2013	B.Com., C.A., President of Tourigny Management Ltd. (Calgary), a private consulting company, since 1979.
Aidan M. Walsh[1][2] Calgary, AB	Director May, 2017	P. Eng., MBA, ICD.D, Chief Executive Officer, Director and co-founder of Baccalieu Energy Inc., a private junior oil and gas company since 2008. Mr. Walsh is also a director of Freehold Royalties Ltd.

Notes:

(1) Member of the Audit Committee. Chaired by Rodger A. Tourigny.
(2) Member of the Reserve Committee. Chaired by Randy Jarock.
(3) Member of the Compensation Committee. Chaired by Dan Reuter
(4) Member of the Disclosure, Policy governance and Nominating Committee. Chaired by Gary Drummond.

All of the directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 8,579,159 common shares representing approximately 25.7 percent of the issued and outstanding common shares of Bonterra as at March 12, 2019 the date of this report.

Cease Trade Orders

To the best of Bonterra's knowledge, no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any company (including the Company) that: (i) while that person was acting in that capacity, was subject to a cease trade or similar order or an order that denied such company access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days; or (ii) was subject to a cease trade or similar order or an order that denied such company access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days that was issued after that person ceased to act in such capacity and which resulted from an event that occurred while that person was acting in such capacity.

Bankruptcies

Other than as set forth below, to the best of Bonterra's knowledge, no director or executive officer of the Company, or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (i) is, as at the date of this Annual Information Form, or has been within the past 10 years, a director or executive officer of any company (including the Company) that while the person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the past 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 its assets.

Mr. Thompson was the Chief Financial Officer of Sonde Resources Corp. (Sonde, formerly Canadian Superior Energy Inc.) when the issuer sought creditor protection under the CCAA. All executive positions at Sonde, other than the Chief Financial Officer and Vice President, Western Canada, were vacated in connection with the application for CCAA protection. Mr. Thompson maintained his employment with the company throughout the CCAA process. Ultimately, Sonde was able to repay its creditors in full, with interest, and it exited CCAA protection in October 2009.

Penalties or Sanctions

To the best of Bonterra's knowledge, no director or executive officer of the Company, or shareholder of the Company holding sufficient securities of the Company to affect materially the control of the Company, has been subject to: (i) 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 (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

AUDIT COMMITTEE INFORMATION

The following information is provided in accordance with Form 52-110F1 under the Canadian Securities Administrators' National Instrument 52-110 - Audit Committees (NI 52-110).

Audit Committee Charter

The Audit Committee Charter is attached as Appendix "C" to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of Randy M. Jarock, Dan Reuter, Rodger A. Tourigny and Aidan M. Walsh. Each director is considered "independent" and "financially literate" (as such terms are defined in NI 52-110).

Relevant Education and Experience

Collectively, the Audit Committee has the education and experience to fulfill the responsibilities outlined in the Audit Committee Charter. The education and current and past experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is summarized as follows:

Name	Education and Experience
Randy M. Jarock	• B. Science (Engineering), businessman and private investor. • Former President and COO of Bonterra Energy Corp. and former COO of Pine Cliff Energy Ltd. • Director and chairman of the audit committee of Pine Cliff Energy Ltd.

Dan Reuter	• Managing Director of Oberndorf Enterprises, a private investment fund. • MBA with many years of experience in valuation and financial modeling. • Direct experience in all aspects of reading and understanding financial statements.
Rodger A. Tourigny (Chairman)	• B. Com., C.A., private investor and financial consultant. • Over 30 years providing advice on major transactions, investments and ongoing financial matters in the oil and gas, real estate and financial services industries. • Many years of experience related to the supervision of the preparation of financial statements and as CFO of oil and gas entities.
Aidan M. Walsh	• B. Eng. (Mechanical), Masters of Business Admin., member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), and holds the ICD.D designation from the Institute of Corporate Directors. • Chief Executive Officer and Director of Baccalieu Energy Inc., a private junior oil and gas company that he co-founded in 2008. • Director of Freehold Royalties Ltd. • Former Director and Chair of the Explorers and Producers Association of Canada (EPAC).

Pre-Approval Policies and Procedures

The Audit Committee is authorized by the Board of Directors to review the performance of the Company's external auditors, and approve in advance provision of services other than auditing and to consider the independence of the external auditors, including reviewing the range of services provided in the context of all consulting services engaged by Bonterra. The Audit Committee is authorized to approve any non-audit services or additional work which the Chairman of the Audit Committee deems as necessary who will notify the other members of the Audit Committee of such non-audit or additional work. The audit committee has specified that management may authorize non-audit services to a maximum amount of $20,000 per project without prior audit committee approval.

External Auditor Service Fees (By Category)

The fees for auditor services billed by the Company's external auditors in each of the last two fiscal years ending December 31, are as follows:

Year	Audit	Audit Related Fees	Tax Fees	All Other Fees
2018	$187,000	$80,000	$ -	$ -
2017	$155,000	$89,000	$ -	$ -

REGULATORY ACTIONS

To the knowledge of Bonterra, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the Company's most recently completed financial year; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set out herein, management is not aware of any material interests, direct or indirect, of any directors or executive officers of Bonterra, any person or company which beneficially owns or controls or directs, directly or indirectly, more than ten percent of the outstanding common shares of the Company, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Company, or during the current financial year which has materially affected or is reasonably expected to materially affect the Company.

INTERESTS OF EXPERTS

Sproule Associates Limited prepared the Sproule Report.

The Company has been advised by Sproule Associates Limited that as of the date hereof, the directors, officers and associates as a group, do not beneficially own, directly or indirectly, any common shares of Bonterra.

The independent auditor of the corporation is Deloitte LLP ("Deloitte"), Independent Registered Chartered Accountants, Calgary, Canada. Deloitte has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

MATERIAL CONTRACTS

During the year ended December 31, 2018, Bonterra has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into the ordinary course of business.

ADDITIONAL INFORMATION

Additional information relating to Bonterra may be found on SEDAR at www.sedar.com. Information including directors' and officers' remuneration, principal holders of Bonterra's securities, and options to purchase securities is contained in Bonterra's Information Circular dated April 3, 2019. Additional financial information is contained in Bonterra's comparative financial statements and management's discussion and analysis of financial conditions and results of operations for the years ended December 31, 2018 and 2017, which are included in Bonterra's Annual Report for the year ended December 31, 2018.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraph please visit our website at www.bonterraenergy.com or contact:

Bonterra Energy Corp.
901, 1015 4^{th} Street S.W.
Calgary, Alberta
T2R 1J4
Attention: Ms. Erin Durtnall
Phone: (403) 750-2564 Facsimile: (403) 265-7488
Email: Edurtnall@bonterraenergy.com

APPENDIX "A"

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

Report on Reserves Data

To the Board of Directors of Bonterra Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

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

5. The following table shows the net present value of future revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2018, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective date	Location of Reserves (Country)	Net Present Value of Future Net revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	**December 31, 2018**	**Canada**	**Nil**	**1,401,383**	**Nil**	**1,401,383**

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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 the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled " Evaluation of the P&NG Reserves of Bonterra Energy Corp. (As of December 31, 2018)"

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 8, 2019

(signed) "Rodney E. Fradette, P. Eng"
Senior Petroleum, Engineer

(signed) "Weldon Dueck, P. Eng."
Senior Petroleum Engineer

(signed) "James D. Hudson, P.L (Eng.)"
Senior Technologist

(signed) Alec Kovaltchouk, P. Geo
Vice-President, Geoscience

(signed) Nora T. Steward P. Eng.
Senior Vice-President, Reserve certification
and Director

APPENDIX "B"

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

Report of Management and Directors on Reserves Data and Other Information

Management of Bonterra Energy Corp. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

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

The board of directors of the Company has:

a) reviewed the Company'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 board of directors of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has 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; and

c) the content and filing of this report.

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

(signed) "George F. Fink"
George F. Fink, Chief Executive Officer

(Signed) "Robb D. Thompson
Robb D. Thompson, Chief Financial Officer

(Signed) "Randy M. Jarock"
Randy M. Jarock, Director

(Signed) "Dan Reuter"
Dan Reuter, Director

(Signed) "Rodger A. Tourigny"
Rodger A. Tourigny, Director

(Signed) "Aidan M. Walsh"
Aidan M.Walsh, Director

(Signed) "Gary J. Drummond"
Gary J. Drummond, Director

March 12, 2019

APPENDIX "C"

AUDIT COMMITTEE CHARTER

Purpose of the Committee

The purpose of the Audit Committee (the "Committee") of the Board of Directors (the "Board") of the Company is to provide an open avenue of communication between management, the Company's independent auditors and the Board and to assist the Board in its overseeing of:

(a) the integrity, adequacy and timeliness of the Company's financial reporting and disclosure practices;
(b) the Company's compliance with legal and regulatory requirements related to financial reporting; and
(c) the independence and performance of the Company's independent auditors.

The Committee shall also perform any other activities consistent with this Charter, the Company's By-laws and governing laws as the Committee or Board deems necessary or appropriate.

The Committee shall consist of at least three directors. Members of the Committee shall be appointed by the Board and may be removed by the Board in its discretion. The members of the Committee shall elect a Chairman from among their number. Each director appointed to the Committee shall be an outside director who is unrelated. An outside, unrelated director is a director who is independent of management and is free of any interest, any business or other relationship which could, or could reasonably be perceived, to materially interfere with the director's ability to act with the view to the best interests of the Company, other than interests and relationships arising from shareholding. In determining whether a director is independent of management, the Board shall make reference to the current legislation, rules, policies and instruments of applicable regulatory authorities. None of the members of the Committee may be officers or employees of the Company or of an affiliate of the Company.

Each member of the Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand basic financial statements.

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

The Committee's role is one of overseeing. Management is responsible for preparing the Company's financial statements and other financial information and for the fair presentation of the information set forth in the financial statements in accordance with International Financial Reporting Standards (IFRS). Management is also responsible for establishing internal controls and procedures and for maintaining the appropriate accounting and financial reporting principles and policies designed to assure compliance with accounting standards and all applicable laws and regulations.

The independent auditors' responsibility is to audit the Company's financial statements and provide their opinion, based on their audit conducted in accordance with Canadian generally accepted auditing standards, that the financial statements present fairly, in all material respects, the financial position, and its financial performance and its cash flows in accordance with IFRS.

The Committee is responsible for recommending to the Board the independent auditors to be nominated for the purpose of auditing the Company's financial statements, preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and for reviewing and recommending the compensation of the independent auditors. The Committee is also directly responsible for the evaluation of and oversight of the work of the independent auditors. The independent auditors shall report directly to the Committee.

Meetings of the Committee

The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chairman of the Committee and whenever a meeting is requested by the Board, a member of the Committee, the auditors, or an executive officer of the Administrator. Meetings of the Committee shall correspond with the review of the quarterly financial statements and Management's discussion and analysis.

Notice of each meeting of the Committee shall be given to each member of the Committee and to the auditors, who shall be entitled to attend each meeting of the Committee and shall attend whenever requested to do so by a member of the Committee.

The quorum for a meeting of the Committee is a majority of the members. With the exception of the foregoing quorum requirement, the Committee may determine its own procedures.

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

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

The following Management representatives shall be invited to attend all meetings, except private Committee sessions and private sessions with the independent auditors:

(i) Chief Executive Officer;
(ii) Chief Financial Officer;
(iii) Chief Operating Officer;
(iv) Senior Vice President, Business Development;
(v) Vice President, Marketing; and
(vi) Corporate Controller

The Chairman of the Board, executive management and other parties may attend meetings of the Committee; however the Committee (i) shall meet with the external auditors independent of management; and (ii) may meet separately with management.

Minutes shall be kept of all meetings of the Committee.

Authority and Responsibilities

In addition to the foregoing, in performing its overseeing responsibilities the Committee shall:

1. Monitor the adequacy of this Charter and recommend any proposed changes to the Board on an annual basis.
2. Review the appointments of the Chief Financial Officer and any other key financial executives involved in the financial reporting process.
3. Identify and monitor the management of the principal risks that could impact the financial reporting of the Company.
4. Review with management and the independent auditors the adequacy and effectiveness of the Company's accounting and financial controls and the adequacy and timeliness of its financial reporting processes.
5. Review with management and the independent auditors the annual financial statements and related documents and review with management the unaudited quarterly financial statements and related documents, prior to filing or distribution, including matters required to be reviewed under applicable legal or regulatory requirements.

6. Where appropriate and prior to release, review with management any news releases that disclose annual or interim financial results or contain other significant financial information that has not previously been released to the public.

7. Review the Company's financial reporting and accounting standards and principles and significant changes in such standards or principles or in their application, including key accounting decisions affecting the financial statements, alternatives thereto and the rationale for decisions made.

8. Review the quality and appropriateness of the accounting policies and the clarity of financial information and disclosure practices adopted by the Company, including consideration of the independent auditors' judgment about the quality and appropriateness of the Company's accounting policies. This review may include discussions with the independent auditors without the presence of management.

9. Review with management and the independent auditor significant related party transactions and potential conflicts of interest.

10. Pre-approve all non-audit services to be provided to the Company by the independent auditors and applicable fees.

11. Inspect any and all of the books and records of the Company and its affiliates.

12. Discuss with the management of the Company and its affiliates and staff of the Company, any affected party, contractors and consultants of the Company and the external auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate.

13. At the earliest opportunity after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

14. When there is to be a change of external auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and documentation required pursuant to National Instrument 51-102 (or any successor legislation) of the Canadian Securities Administrators and the planned steps for an orderly transition.

15. Review all securities offering documents (including documents incorporated therein by reference) of the Company.

16. Review findings, if any, from examinations performed by regulatory agencies with respect to financial matters.

17. Review management's procedure for monitoring the Company's compliance with laws and regulations.

18. Review current and expected future compliance with covenants under financing agreements.

19. Review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases. When applicable, the Committee shall review the related securities filings.

20. Monitor the independence of the independent auditors by reviewing all relationships between the independent auditors and the Company and all non-audit work performed for the Company by the independent auditors.

21. Establish and review the Company's procedures for the:

    (a) receipt, retention and treatment of complaints regarding accounting, financial disclosure, internal controls or auditing matters; and

    (b) confidential, anonymous submission by employees regarding questionable accounting, auditing and financial reporting and disclosure matters.

22. Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.

23. Conduct or authorize investigations into any matters that the Committee believes is within the scope of its responsibilities. The Committee has the authority to retain independent counsel, accountants or other advisors to assist it, as it considers necessary, to carry out its duties, and to set and pay the compensation of

such advisors at the expense of the Company. If these costs exceed $10,000 per annum for a Committee member, such member will obtain prior approval from the Board for the amount exceeding $10,000 per annum.

24. Perform such other functions and exercise such other powers as are prescribed from time to time for the audit committee of a reporting company in Parts 2 and 4 of Multilateral Instrument 52-110 of the Canadian Securities Administrators, all other applicable laws and policies and procedures of all applicable regulatory authorities, the *Business Corporations Act* (Alberta) and the By-laws of the Company.