BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2017

March 13, 2018

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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 January 31, 2018 and effective December 31, 2017 utilizing commodity price forecasts of Sproule dated December 31, 2017; and

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

ABBREVIATIONS

Oil and Natural Gas Liquids	Natural Gas
Bbl – barrels MBbl – thousand barrels Bbl/d – barrels per day NGLs – natural gas liquids	GJ – gigajoules GJ/d – gigajoules per day Mcf – thousand cubic feet 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 high-yield, 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.

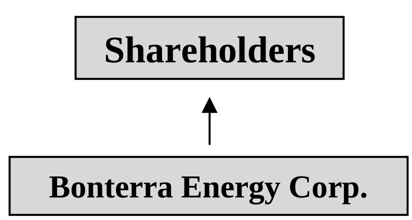
The Company's primary focus is to maximize total return to shareholders by growing production and maintaining and enhancing cash dividends through the optimum utilization and development of existing crude oil and natural gas properties and acquisition and development of new producing or undeveloped properties. 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, 2017, 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 2017, 2016 and 2015

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.

On April 15, 2015, Bonterra acquired certain oil and gas assets from a senior oil and gas producer, adding production of approximately 1,700 BOE per day. The assets are Cardium focused in the Pembina area, complementary to current Bonterra acreage. Bonterra paid $170 million, before adjustments, financed mainly through bank debt. The transaction had an effective date of January 1, 2015.

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, 2017 contained in the Sproule Report dated January 31, 2018.

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, 2017 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, 2017
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	25,760.1	23,340.9	73,750	67,360	3,146.9	2,480.5	41,198.7	37,048.0
Developed Non-Producing	616.5	584.7	1,712	1,555	68.8	54.4	970.5	898.3
Undeveloped	22,369.3	20,010.3	65,915	60,635	3,067.8	2,711.7	36,422.9	32,827.9
TOTAL PROVED	48,745.9	43,935.9	141,377	129,550	6,283.5	5,246.6	78,592.1	70,774.2
PROBABLE	13,147.9	11,003.9	38,498	34,753	1,684.0	1,368.9	21,248.2	18,164.9
TOTAL PROVED PLUS PROBABLE	61,893.8	54,939.8	179,875	164,302	7,967.5	6,615.5	99,840.4	88,939.0

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, 2017
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	1,379.2	935.5	706.1	569.5	479.6	19.1
Developed Non-Producing	20.8	18.1	14.9	12.3	10.3	16.5
Undeveloped	930.6	514.7	306.5	190.4	120.0	9.3
TOTAL PROVED	2,330.6	1,468.3	1,027.4	772.2	609.9	14.5
PROBABLE	946.3	492.7	317.6	231.2	180.8	17.5
TOTAL PROVED PLUS PROBABLE	3,276.9	1,961.0	1,345.0	1,003.4	790.8	15.1

(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, 2017
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	1,117.1	777.8	599.1	491.2	419.4
Developed Non-Producing	15.1	13.2	10.8	8.9	7.5
Undeveloped	677.1	360.3	200.1	111.0	57.4
TOTAL PROVED	1,809.3	1,151.3	810.1	611.1	484.3
PROBABLE	687.3	359.4	231.8	168.9	132.2
TOTAL PROVED PLUS PROBABLE	2,496.5	1,510.7	1,041.9	780.0	616.5

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(b)
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2017
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	5,522.0	563.5	1,915.9	606.3	105.7	2,330.6	521.3	1,809.3
PROVED PLUS PROBABLE	7,272.7	830.4	2,432.1	615.9	117.4	3,276.9	780.3	2,496.5

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, 2017
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)	1,012.8	15.23
	Conventional Natural Gas (Including associated by-products)(2)	14.6	3.42
Total		1,027.4	
Proved Plus Probable	Light And Medium Crude Oil (Including solution gas and associated by-products)	1,320.9	15.84
	Conventional Natural Gas (Including associated by-products)(2)	24.1	4.35
Total		1,345.0	

(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 ($Cdn/ bbl)	NGL Pentanes Edmonton ($Cdn/bbl)	Operating Cost Inflation Rate (%/Yr)	Capital Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
HISTORICAL							
2013	93.27	3.13	69.88	105.48	1.0	0.7	0.971
2014	93.99	4.50	68.02	102.39	2.0	(1.0)	0.905
2015	57.45	2.70	36.81	61.45	1.8	(23.2)	0.783
2016	52.80	2.18	34.32	55.71	1.2	(3.4)	0.755
2017	61.84	2.20	44.11	67.21	2.2	(3.4)	0.771
FORECAST(1)(2)							
2018	65.44	2.85	48.73	67.72	-	-	0.790
2019	74.51	3.11	55.49	75.61	2.0	2.0	0.820
2020	78.24	3.65	57.65	78.82	2.0	2.0	0.850
2021	82.45	3.80	60.12	82.35	2.0	2.0	0.850
2022	84.10	3.95	61.32	84.07	2.0	2.0	0.850
2023	85.78	4.05	62.55	85.82	2.0	2.0	0.850
2024	87.49	4.15	63.80	87.61	2.0	2.0	0.850
2025	89.24	4.25	65.07	89.43	2.0	2.0	0.850
2026	91.03	4.36	66.37	91.29	2.0	2.0	0.850
2027	92.85	4.46	67.70	93.19	2.0	2.0	0.850
2028	94.71	4.57	69.06	95.12	2.0	2.0	0.850

(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 historical prices by production type for the 2017 financial year are as follows:

Light and Medium Crude Oil ($ per barrel)	59.30
Conventional Natural Gas ($ per Mcf)	2.40
Natural Gas Liquids ($ per barrel)	31.47

PART IV – RECONCILIATION OF CHANGES IN RESERVES

RECONCILIATION OF COMPANY GROSS RESERVES (BEFORE ROYALTY) BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2017 FORECAST PRICES AND COSTS

	Light and Medium Crude Oil (MBbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
PROVED				
December 31, 2016	**47,580.8**	**129,108**	**5,157.6**	**74,256.2**
Extensions[1]	4,085.6	7,130	427.1	5,701.2
Technical Revisions	(881.6)	11,905	959.7	2,062.3
Discoveries	-	-	-	-
Acquisitions	697.4	1,730	56.9	1,042.6
Dispositions	-	-	-	-
Economic Factors	149.7	295	12.7	211.6
Production	(2,886.0)	(8,792.0)	(330.5)	(4,681.8)
December 31, 2017	**48,745.9**	**141,376**	**6,283.5**	**78,592.1**
PROBABLE				
December 31, 2016	**12,739.1**	**38,161**	**1,549.3**	**20,648.7**
Extensions[1]	1,080.1	1,879	205.1	1,505.7
Technical Revisions	(903.0)	(2,102.0)	(87.9)	(1,248.6)
Discoveries	-	-	-	-
Acquisitions	170.1	440	14.4	257.9
Dispositions	-	-	-	-
Economic Factors	61.6	119	3.1	84.6
Production	-	-	-	-
December 31, 2017	**13,147.9**	**38,498**	**1,684.0**	**21,248.4**
PROVED PLUS PROBABLE				
December 31, 2016	**60,319.9**	**167,269**	**6,706.9**	**94,904.9**
Extensions[1]	5,165.7	9,009	632.2	7,207.1
Technical Revisions	(1,784.6)	9,803.0	871.8	813.7
Discoveries	-	-	-	-
Acquisitions	867.5	2,170	71.3	1,300.5
Dispositions	-	-	-	-
Economic Factors	211.3	415	15.8	296.2
Production	(2,886.0)	(8,792.0)	(330.5)	(4,681.8)
December 31, 2017	**61,893.8**	**179,874**	**7,967.5**	**99,840.4**

(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
2015	3,787	19,447	6,586	45,587	421	2,186	5,306	29,231
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

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
2015	1,244	5,576	2,271	17,751	139	824	1,762	9,359
2016	919	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

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

As of December 31, 2017, Sproule's evaluation of Bonterra's reserves are in accordance with the COGE Handbook. However, Sproule's report includes undeveloped locations with development timing beyond the COGE Handbook recommended guidance of three years for the assignment of proved reserves. This delay has no consequent impact on the confidence level associated with the reserves estimate and in each category, the Company is committed to its development plan.

The majority of the Company's reserves occur in the Pembina and Willesden Green Cardium fields located in central Alberta. There are 320 drilling locations in the Cardium to which proved undeveloped and proved plus probable undeveloped reserves have been assigned. All of these locations are scheduled to be developed within five years. However, there are 158 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 102 future drilling locations scheduled to be developed in the fourth year (2021) and 56 future drilling locations scheduled to be developed in the fifth year (2022) to which proved undeveloped reserves were 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.

Bonterra's proved undeveloped reserves amount to 36,423 MBOE and represent approximately 46.3 percent of the total proved reserves and 36.5 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 10,114 MBOE and represent approximately 10.1 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 2017 Annual Report.

Future Development Costs

$ 000s	Forecast Prices and Costs	
Year	Proved	Proved Plus Probable
2018	69,028	69,028
2019	107,110	107,110
2020	141,506	142,005
2021	173,903	183,056
2022	114,728	114,728
Total Undiscounted	606,275	615,926

The above future development costs will be funded primarily from 2018 to 2022 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 2017, 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, 2017, Bonterra's oil and natural gas properties yielded average production of 12,827 BOE per day (2016 – 12,650 BOE per day, 2015 – 12,656 BOE per day). As at December 31, 2017 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 99,840 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 99.3 percent of Proved plus Probable reserves. Production is primarily oil and solution gas from the Cardium formation and to a lesser extent natural gas from the Edmonton Sands, Belly River, Paskapoo and the Ardley Coals.

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 14 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 89 percent of its production with an average land working interest of 76 percent.

Bonterra has identified 1,051 gross (739 net) potential horizontal drilling locations within its acreage. Currently only 327 gross (279 net) undeveloped horizontal drilling locations are reflected in Bonterra's 2017 reserve report.

During 2017 the Company invested $60.7 million to drill 30 gross (27.9 net) operated horizontal wells and complete and tie-in 33 gross (29.6 net) wells (of which three (1.7 net) wells were drilled in 2016, but not completed until 2017) in the Cardium formation with a 100 percent success rate. The Company also invested approximately $17 million to reduce future operating costs by enhancing water and gas handling capabilities and other non-operated capital programs.

The Company reduced its debt levels in December of 2017, due to $52 million of cash received for the sale of a two percent overriding royalty interest on the Pembina Cardium properties. Realized commodity prices also improved in 2017 leading to increased cash flow over 2016. To manage debt levels and maximize cash flow Bonterra reduced its planned capital expenditures for the 2015, 2016 and 2017 fiscal years compared to 2014.

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 2017 was 162 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 225 BOE per day for 2017.

As natural gas prices have remained depressed in 2017, 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 2018 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, 2017 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 63,676 gross and 44,228 net undeveloped acres.

None of these land rights require any work commitment and 577.5 gross (263 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 the Alberta's Energy Resources Conservation Board, 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, net of estimated salvage value for such equipment, to be approximately $298,111,000 on an undiscounted basis and $19,527,000 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 $180,752,000 on an undiscounted basis and $14,372,000 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	92,306
Share issue costs	20	107
Canadian oil and gas property expenditures	10	100,746
Canadian development expenditures	30	151,862
Canadian exploration expenditures	100	8,063
Federal income tax losses carried forward (1)	100	54,221
Provincial income tax losses carried forward (2)	100	15,989
		423,294

(1) Federal income tax losses carried forward expire in the following years; 2035 - $18,151,000; 2036 - $35,853,000; 2037 - $217,000

(2) Provincial income tax losses carried forward expire in 2036 - $ 15,772,000; 2037 - $217,000

The Company has $8,834,000 (December 31, 2016 - $8,834,000) of investment tax credits that expire in the following years; 2021 - $1,824,000; 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 $64,435,000 (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)	2017	2016
Land	-	-
Acquisitions - proved properties	-	-
Disposals	(56,752) (1)	(54)
Exploration and development costs	82,441 (1)	40,851
Net petroleum and natural gas capital expenditures	25,689	40,797

(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:

	2017					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	30.0	27.9	-	-	30.0	27.9
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	30.0	27.9	-	-	30.0	27.9
Success rate	100%	100%	-	-	100%	100%

	2016					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	23.0	18.8	-	-	23.0	18.8
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	23.0	18.8	-	-	23.0	18.8
Success rate	100%	100%	-	-	100%	100%

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

Production Estimates 2018

	2018			
	Light and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (Bbl/d)	Total (BOE/d)
Alberta[1]	8,885	24,842	1,075	14,099
British Columbia	-	412	1	70
Saskatchewan	113	-	-	114
	8,998	25,254	1,076	14,283

(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 2017

Product Type Yearly Quarter	Production Volume per day	Average per Unit of Volume ($/Bbl and $/Mcf) Price	Royalties	Production Costs	Netbacks
Light and Medium Crude Oil (Bbl)					
1 Quarter	7,533	60.63	3.14	16.80	40.69
2 Quarter	8,287	58.27	3.06	15.26	39.95
3 Quarter	8,038	53.48	2.59	15.96	34.93
4 Quarter	7,766	65.16	3.37	20.21	41.58
Conventional Natural Gas (Mcf)					
1 Quarter	22,243	2.97	0.52	1.19	1.26
2 Quarter	24,138	3.03	0.51	1.00	1.52
3 Quarter	25,460	1.81	0.43	1.04	0.34
4 Quarter	24,466	1.90	0.56	0.92	0.42
Natural Gas Liquids (Bbl)					
1 Quarter	813	31.00	3.14	11.69	16.17
2 Quarter	843	27.48	3.06	12.76	11.66
3 Quarter	1,000	27.81	2.59	11.90	13.32
4 Quarter	963	39.12	3.37	10.38	25.37

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

	2017 Light and Medium Crude Oil and NGL (Bbl per day)	Conventional Natural Gas (Mcf per day)	Total (BOE per day)
Alberta	8,652	22,723	12,440
Saskatchewan	154	50	162
British Columbia	6	1,313	225
	8,812	24,086	12,827

Lease Holdings

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

	2017		2016	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	313,909	192,945	297,388	180,150
Saskatchewan	8,178	5,647	8,865	6,193
British Columbia	62,045	22,594	62,045	22,638
	384,132	221,186	368,298	208,981

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 14 of Bonterra's audited annual financial statements for the year ended December 31, 2017, contained in the Company's 2017 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 37 persons and contracted numerous office and field operations personnel.

INDUSTRY CONDITIONS

Government Regulation

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 Although, 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.

Crude Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, availability of infrastructure, the value of refined products, the supply/demand balance, other contractual terms and the world price for oil.

Natural Gas

In Canada the price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas and other fuels, on natural gas quality, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms.

The government of Alberta also regulates the volume of natural gas which may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market conditions.

Natural Gas Liquids

The price of condensate and other natural gas liquids ("NGLs") sold in intra-provincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the demand/supply balance and other contractual terms.

Export from Canada

While exporters are free to negotiate prices and other terms with purchasers, crude oil exported from Canada, is subject to regulation by the National Energy Board (NEB).

Crude oil must be exported pursuant to either an export order or an export licence from the NEB. Crude oil exports for a term less than one year for light and medium crude, or two years for heavy crude, may be made pursuant to an export order. Any oil export for a longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB which requires the approval of the Governor in Council (i.e. Federal Cabinet).

The price of natural gas is also determined by negotiation between buyers and sellers and natural gas exported from Canada is also subject to regulation by the NEB and the Government of Canada. While exporters are free to negotiate prices and other terms with purchasers, natural gas must be exported pursuant to either an export order or an export licence from the NEB. Natural gas exports (other than propane, butane and ethane) for a term of less than two years, or for a term of two to 20 years in quantities of not more than 30,000 m^3/day, may be made pursuant to an NEB export order. Exporters are required to obtain an export license from the NEB for natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas. The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Bonterra does not export directly.

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity and Canadian oil's ability to access the United States midwest and tidewater is constrained. The transportation capacity deficit is not likely to be resolved quickly given that production of heavy oil and bitumen in Canada is expected to continue to increase. As further outlined below, several pipeline projects have been proposed and are in the approvals stage, and others have recently been completed. If the proposed projects are approved and constructed, the pipelines would help to alleviate the problems that Canada faces in accessing global markets for its oil supply.

Pipeline Capacity

Despite the pipeline expansions over the past several years, there appears to be insufficient pipeline capacity to accommodate current production levels of oil and natural gas in Western Canada. Pipeline capacity may limit the ability to produce and market such production, and therefore western Canadian production may receive discounted pricing. Current pipeline construction projects before various regulatory bodies, if approved, are expected to alleviate this risk.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. 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 on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Pipeline Projects

The proposed TransCanada Energy East pipeline would carry 1.1 million bbls/d of crude oil from Saskatchewan and Alberta to refineries in Eastern Canada and to a tidewater export terminal in Saint John, New Brunswick. In April 2016, the NEB released a preliminary timeline for the Energy East hearing process with an NEB report to the Governor-in-Council expected in March 2018. Energy East panel sessions began in New Brunswick in August 2016, but were later suspended following protests at a panel session in Montreal. In January, 2017, the NEB announced the appointment of three new panel members who will be responsible for continuing the review of the project.

In 2014, the NEB approved the Northern Gateway Pipeline with 209 conditions attached. The pipeline would have carried up to 525,000 bbls/d from Alberta to Kitimat, British Columbia for export; however in November 2016, the Government of Canada officially rejected the Northern Gateway proposal.

Kinder Morgan Canada's proposed expansion of its existing Trans Mountain Pipeline from Edmonton, Alberta to Burnaby, BC was approved by the NEB in May, 2016, and by the federal government in November, 2016. The pipeline is expected to increase capacity by 590,000 bbls/d.

Enbridge's Line 3 proposed replacement project of its existing pipeline from Hardisty, Alberta to Wisconsin, USA was approved by the NEB in April, 2016, and by the federal government in November, 2016. The pipeline is expected to increase capacity by 370,000 bbls/d.

The TransCanada-led Keystone XL project would add 830,000 bbls/d in pipeline capacity for Canadian crude oil to flow to the American Gulf Coast market. The project may proceed following the executive order issued by President Trump inviting TransCanada to re-submit its application for a presidential permit, which it did on January 26, 2017.

The North American Free Trade Agreement

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. 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*.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian oil and natural gas exports. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain. Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. As of the date hereof, renegotiation discussions continue and the outcome of such negotiations remains unclear. As the United States remains Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry, including our business.

The Trans-Pacific Partnership Agreement

In October 2015, the Canadian government concluded negotiations of a free trade agreement between the members of the Trans-Pacific Partnership, which includes Canada, Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore, the United States and Vietnam. The Canadian government is currently in the process of consulting with Canadians on the agreement and states that it will provide greater transparency and more predictable market access for cross-border trade in services related to the oil and gas industry.

The finalized proposal was signed on February 4, 2016. It currently cannot be ratified due to U.S. withdrawal from the agreement on January 23, 2017.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with countries around the world. 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. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

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.

Oil sands leases are continued beyond their primary term by performing a minimum level of evaluation by drilling and coring all potential producing hydrocarbon bearing zones or by meeting a minimum level of production.

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.

Royalties

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. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to reduce the benefits under such programs and to allow them to expire without renewal, and consequently few such programs are currently operative.

The Canadian federal government has signaled that it will inter alia phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration and implementing stringent reviews for pipelines. Additionally, in December 2016, the federal government issued the Pan-Canadian Framework on Clean Growth and Climate Change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

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, 216, 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.

Incentive Programs - Alberta

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.

Taxes on Freehold Production

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Royalties-Saskatchewan

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.

Canadian Environmental Regulation

The 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 and facility 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. 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 with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the Fisheries Act and the Navigation Protection Act. An Expert Panel has been convened to review federal environmental assessment processes and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel’s report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes-if any-will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

On November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast.

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 effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced 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 second reading on October 4, 2017. 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 Alberta Climate Leadership Plan introduced a new GHG emissions pricing regime. The Climate Leadership Act (the "CLA") came into force on January 1, 2017. The Climate Leadership Regulation ("CL Regulation"), which provides further detail in respect of the carbon levy regime set out in the CLA, and also came into force on January 1, 2017. The CLA establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel, based on rates of $20 per tonne of GHG emissions as of January 1, 2017 and $30 per tonne for 2018. The carbon levy revenue will be used to fund initiatives to reduce GHG emissions, to support Alberta's ability to adapt to climate change and for rebates or adjustments related to the carbon levy to consumers, businesses, and communities in addition to a household rebate program.

The CLA and the CL Regulation impose registration, payment, remittance, reporting and administrative obligations on applicable persons throughout the fuel supply chain. The application of the carbon levy depends on the type and quantity of fuel purchased or produced and how such fuel is used by the purchaser.

GHG emissions are regulated under the Specified Gas Reporting Regulation (the "SGRR") and the Carbon Competitiveness Incentive Regulation (the "CCIR"), both pursuant to the Climate Change and Emissions Management Act (Alberta). The SGRR requires facilities that emit 10,000 tonnes or more of GHG per year to report their emissions to Alberta Environment and Parks. The CCIR, which replaced the Specified Gas Emitters Regulation on January 1, 2018, requires facilities that emit more than 100,000 tonnes of GHG per year (or facilities that opt-in so they may apply for a carbon levy exemption) to meet product specific emissions intensity benchmarks. Most benchmarks are based on 80% production-weighted average emissions intensity, which means the 20% least-emissions intensive competitors face no CCIR compliance costs. For oil and gas refining, a best-in-class benchmark applies (meaning the benchmark is no more stringent than the best-performing emissions facility producing the product). Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. The use of fund credits is unlimited; however, the use of other credits is capped, such that a facility may address only 50-60% of its excess emissions through performance credits and emissions offsets. Additionally, credits will expire depending on their vintage.

Under the CLA and CL Regulations, facilities subject to the CCIR are exempt from the carbon levy. Activities integral to oil and gas production processes are exempt until 2023. At this time, the determination of what constitutes an activity that is “integral” to conventional oil and gas production is still being clarified with the Alberta government. The Company expects current operations to have minimal direct carbon levy exposure until 2023. It is not known what will occur in 2023 when the current exemptions are expected to end.

Saskatchewan

The Management and Reduction of Greenhouse Gases Act (the “MRGGA”) received Royal assent in the Province of Saskatchewan on May 20, 2010. Portions of the MRGGA came into force on January 1, 2018. This legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulations. A draft of the proposed regulations to accompany the Act calls for a reduction of emissions by 20% below 2006 levels by 2020.

In December 2017, Saskatchewan introduced *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*, which is to be fully implemented by January 1, 2019. This strategy will include reporting requirements and emissions reduction targets for the upstream oil and gas industry and output-based performance standards for facilities emitting more than 25,000 tonnes of carbon dioxide equivalent per year. Large emitters will have various compliance options, including making improvements at facilities to reduce emissions intensity, purchasing a carbon offset, using best performance credits, paying into a technology fund and using market mechanisms outlined in the Paris Agreement.

British Columbia

British Columbia's *Environmental Assessment Act* creates an environmental assessment process for reviewing the potential environmental impact of major energy projects within the province. On February 27, 2007, the Government of British Columbia unveiled the BC Energy Plan, which outlines the province's energy strategy. The BC Energy Plan sets targets for reducing GHG emissions, promoting investments in innovation, and sustainable environmental management. The BC Energy Plan's objectives are to achieve clean energy through conservation and energy efficient practices, and to increase competitiveness in order to attract new investment in the oil and natural gas industry. In furtherance of these initiatives, the Government of British Columbia introduced the *Carbon Tax Act* on July 1, 2008. The carbon tax applies to fuels such as gasoline, diesel, natural gas, propane and coal, and it is revenue-neutral, meaning tax revenues will be returned to taxpayers through reductions in other provincial taxes.

Federal (Canada)

In December, 2015 the United Nations Framework Convention on Climate Change (the “UNFCCC”) members met in Paris, France. Canada, along with 195 other countries, signed a new climate agreement (the “Paris Agreement”). Under the Paris Agreement, Canada is legally bound to report and monitor its GHG emissions, though details of how this will take place have yet to be determined. Signatory counties agreed to meet every five years to review their individual progress on GHG emissions reductions and consider amendments to their targets. The Paris Agreement came into force on November 4, 2016.

On October 3, 2016 the Government of Canada announced a pan-Canadian approach to the pricing of GHG emissions. The federal plan provides all Canadian provinces and territories a year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a standard to be prescribed, failing which the federal government will begin to levy its own carbon tax on a broad set of emission sources.

The initial default carbon tax is expected to begin at $10 per tonne of GHG emissions on January 1, 2018 and increase by $10 per tonne per year until it reaches $50 per tonne in 2022.

The Pipeline Safety Act ("PSA"), which came into force in June 2016, amended the NEB Act and the Canada Oil and Gas Operations Act in order to strengthen the safety and security of pipelines. The PSA reinforces the "polluter pays" principle, such that operators of pipelines are liable for costs and damages of all unintended or uncontrolled releases of oil, gas or other substances. Canada was the first country to introduce absolute liability irrespective of fault, with liability in amounts up to $1 billion for major pipelines (i.e., with transport capacity over 250,000 bbls/d) or otherwise as prescribed by regulation for pipelines with lower capacity. In instances involving fault or negligence, liability is unlimited. Operators are required to maintain the financial resources necessary to meet the applicable absolute liability obligations imposed under the PSA, which is another uniquely Canadian feature of the legislation. Additionally, the PSA authorizes the NEB to impose more stringent requirements with respect to abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs.

Where a company is unable or unwilling to adequately respond to or clean up releases from a pipeline, the NEB has the authority to take control of that pipeline release. Claims against pipeline operators who are at fault for a pipeline release may be initiated within three years from the day on which the damage or costs were incurred and cannot be made beyond six years after the release. Such claims are to be adjudicated by a tribunal established by the PSA.

Abandonment and Reclamation Cost Risk

The current oil and gas asset abandonment, reclamation and remediation (“A&R”) liability regime in Alberta as a general rule limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner becomes insolvent and is unable to fund the A&R activities, the solvent counterparties can claim the insolvent party’s share of the remediation costs against the Orphan Well Association (the “OWA”). The OWA administers orphaned assets and is funded through a levy imposed on licencees, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. Saskatchewan has a similar regime.

In May 2016, the Alberta Court of Queen’s Bench issued a decision in the case of Redwater Energy Corporation, (Re) (“Redwater”) that trustees and receivers of insolvent parties may disclaim or renounce uneconomic oil and gas assets to the AER before commencing the sales process for the insolvent party’s assets. These wells and facilities then become “orphans” to be remediated by the OWA. Prior to Redwater, the sales process for the insolvent party’s assets would have typically included both the economic and uneconomic assets, and only in instances where the sales process failed to sell all of the assets, would the remaining assets be classified as orphaned assets by the AER and disclaimed to the OWA. On April 24, 2017, the Alberta Court of Appeal upheld the Redwater decision. In November 2017, the AER was granted leave to appeal the Redwater Appeal to the Supreme Court of Canada.

In June 2016, in response to Redwater, the AER released Bulletin 2016-16 which, among other things, implements important changes to the AER’s procedures relating to liability management ratings, licence eligibility and transfers.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator’s Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

1. The licensee already has an LMR of 2.0 or higher;
2. The acquisition will improve the licensee's LMR to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement.

The governments of British Columbia and Saskatchewan have announced similar policies within those provinces. These changes may impact Bonterra’s ability to transfer its licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

The AER has also implemented the inactive well compliance program to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 13 – Suspension Requirements for Wells. This program applies to all inactive wells that are noncompliant with Directive 13 as of April 1, 2015. The objective is to bring all inactive noncompliant wells into compliance with the requirements of Directive 13 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 13 or by abandoning them in accordance with Directive 20 – Well Abandonment. The list of current wells subject to the AER's inactive well compliance program is available on the AER's Digital Data Submission system.

Accountability and Transparency

On June 1, 2015, the federal *Extractive Sector Transparency Measures Act*, ("**ESTMA**") came into effect. This new federal legislation imposes mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", which includes exploration, extraction and holding permits to do so. All companies subject to ESTMA are required to report payments over CDN $100,000 made to any level of a Canadian or foreign government, 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. These categories are separate; therefore, even if the aggregate of payments across the categories are greater than $100,000, one or more individual categories must reach the threshold for the report to be required. The reporting requirement for payments made to First Nations governments has been deferred until May 31, 2017.

Any persons or entities found in violation of the Act (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to $250,000 for each day that the offence continues. There is a further fine of up to $250,000 for any person or entity who has structured payments in order to avoid the obligation to report such payments under the ESTMA. Officers or directors who authorized or acquiesced in the commission of an offence can be subject to personal liability, regardless of whether the entity for which they acted has been prosecuted or convicted. The ESTMA contains a due diligence defense whereby no person will be found guilty of an offence under the ESTMA if the person can establish that he or she exercised due diligence to avoid committing the offence. Additionally, there is a five year limitation period within which proceedings must be brought for offences under the ESTMA.

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.

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, 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 Corporation's assets may be subject to impairment.

Exploration and Development

Exploitation and development risks arise due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which Bonterra has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling will be used by Bonterra to improve is ability to find, develop and produce oil and natural gas.

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.

Operations

Bonterra's operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blow-outs, craterings, fires, vandalism or terrorism, all of which could result in personal injuries, loss of life and damage to property of Bonterra and others. Bonterra has both safety and environmental policies in place to protect its operators and employees, as well as to meet the regulatory requirements in those areas where they operate. In addition, Bonterra has liability insurance policies in place in such amounts as it considers adequate, however, it will not be fully insured against all of these risks, nor are all such risks insurable. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Bonterra may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. The payment of such uninsured liabilities would reduce the funds available to it. The occurrence of a significant event that Bonterra is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bonterra's financial position, results of operations or prospects.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Bonterra to certain properties.

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 Corporation 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.

Environmental Risk: 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.

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

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.

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.

Climate Change Regulations

The Company's exploration and production facilities and other operations and activities emit GHG's and require the Company to comply with Alberta's greenhouse gas emissions legislation contained in the Climate Change and Emissions Management Act and the Specified Gas Emitters Regulation. The Company may also be required to comply with the regulatory scheme for GHG emissions ultimately adopted by the federal government, which is currently adopting sector-by-sector regulations. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of GHG regulations, including increases to the compliance costs contained in the Specified Gas Emitters Regulation and Alberta's new initiative to reduce venting and fugitive methane emissions, could also have a material impact on the nature of oil and natural gas operations, including those of the Company.

As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada has committed to reduce GHG emissions by 30% below 2005 levels by 2030. The mechanisms that will be implemented to meet this target have not been finalized. The Government of Canada also announced it would implement a Canada wide price on carbon to further reduce its greenhouse gas emissions. In addition, on January 1, 2017, the Climate Leadership Act came into effect in the Province of Alberta introducing a carbon tax on almost all sources of greenhouse gas emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. 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 not possible to predict the impact on Bonterra and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

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 Management

Shareholders will be dependent on the management of Bonterra in respect of the administration and management of all matters relating to Bonterra and its operations and administration. The loss of the services of key individuals could have a detrimental effect on Bonterra. Investors who are not willing to rely on the management of Bonterra should not invest in the common shares.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally 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 required. Changes of the ratio of Bonterra's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system 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 gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions - Liability Management Rating Programs*".

Information Technology Systems and Cyber-security

Bonterra depends upon the availability, capacity, reliability and security of its information technology infrastructure to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts and communicate with employees and third-party partners. 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 Bonterra'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 its business activities or competitive position. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as reputation. Bonterra applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. 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 Corporation's business, financial condition and results of operations.

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 production from typical oil, natural gas and NGL reserves.

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.

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.

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 Corporation cannot be predicted, however, such impacts could be negative and could have a material adverse effect on the Corporation'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 were owing 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 Corporation 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 Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation'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.

Pipeline Systems

The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. 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.

Forward-Looking Information May Prove Inaccurate

Investors are cautioned not to place undue reliance on 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, 2017, as contained in the Company's Annual Report for the year ended December 31, 2017 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 2015:

Month of Record and Payment Date	Amount per Share
January 2015	$0.30
February 2015	$0.15
March 2015	$0.15
April 2015	$0.15
May 2015	$0.15
June 2015	$0.15
July 2015	$0.15
August 2015	$0.15
September 2015	$0.15
October 2015	$0.15
November 2015	$0.15
December 2015	$0.15
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

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 2017 and 2016 in the shares of the common stock of the Company are as follows:

	December 31, 2017		December 31, 2016	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**33,302,435**	**763,788**	33,143,435	760,020
Issued pursuant to the Company share option plan	**8,361**	**143**	159,000	3,253
Transfer from contributed surplus to share capital		**46**	-	515
Balance, end of year	**33,310,796**	**763,977**	33,302,435	763,788

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 3,331,080 (December 31, 2016 – 3,330,244) 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, 2017 and December 31, 2016, and changes during the years ended on those dates is presented below:

	Number of options	**Weighted average exercise price**
At January 1, 2016	2,955,500	$40.28
Options granted	935,000	25.50
Options exercised	(159,000)	20.46
Options forfeited	(152,500)	43.16
Options expired	(842,000)	58.86
At December 31, 2016	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

(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, 2017:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number outstanding at December 31, 2017	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2017	Weighted-average exercise price
$ 14.00 - $ 30.00	2,698,000	1.8 years	$ 18.24	845,000	$ 25.75
30.01 - 40.00	33,000	0.4 years	33.69	25,000	34.24
40.01 - 65.00	75,000	0.1 years	57.88	75,000	57.88
$ 17.00 - $ 65.00	2,806,000	1.7 years	$ 19.48	945,000	$ 28.52

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 2017	$24.37 - $29.76	1,162,600
February 2017	$23.25 - $26.00	1,134,200
March 2017	$20.45 - $24.65	2,169,300
April 2017	$18.71 - $23.97	1,373,800
May 2017	$15.61 - $19.68	2,871,900
June 2017	$14.53 - $17.32	4,721,300
July 2017	$15.11 - $17.50	1,631,700
August 2017	$14.18 - $16.96	2,713,900
September 2017	$15.34 - $17.27	3,052,300
October 2017	$13.44 - $16.55	3,073,300
November 2017	$13.94 - $17.41	4,485,500
December 2017	$13.76 - $15.80	3,255,500

On December 31, 2017, the closing price of Bonterra shares on the TSX was $15.30 (December 31, 2016 - $29.09).

The Company as of December 31, 2017 had 33,310,796 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[(1)] Nassau, Bahamas	Director August, 1999	B.A., LLB., Mr. Drummond is a private investor and a director of Pine Cliff Energy Ltd.

George F. Fink Calgary, AB	CEO, Director and Chairman January, 1981	B.Com., C.A., Executive Chairman of the Board of Pine Cliff Energy Ltd and a director of Raging River Exploration Inc. (public resource companies)
Randy M. Jarock(1) 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. Prior thereto, Mr. Neumann was Lead Project Manager at Nexen Inc. and has previously held positions of increased responsibility for major oil and gas companies.
Robb D. Thompson Calgary, AB	CFO & Corporate Secretary February 2011	B.Com., C. A., Mr. Thompson has been CFO and Corporate Secretary since February 2011.
Rodger A. Tourigny(1) Calgary, AB	Director May, 2013	B.Com., C.A., President of Tourigny Management Ltd. (Calgary), a private consulting company, since 1979. Vice President of Finance of Siebens Oil and Gas Ltd. From 1976 to 1979 and Secretary Treasurer of Ranger Oil Canada Ltd. From 1969 to 1976. Mr. Tourigny was director of LED Medical Diagnostics Inc. until his resignation on December 31, 2017.
Aidan M. Walsh(1) 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.

All five board members are on the Compensation committee; Policy, Governance and Nominating committee; Disclosure committee; and Reserves committee.

All of the directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 4,146,149 common shares representing approximately 12.4 percent of the issued and outstanding common shares of Bonterra as at March 13, 2018 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 Gary J. Drummond, Randy M. Jarock, 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
Gary J. Drummond	• B.A. (Economics), LLB., businessman and private investor. • Director of several public corporations and a member of the Audit Committee of certain of those corporations. • 35 years of extensive experience directly related to all aspects of reading and understanding financial statements and matters. • Former President and CEO of Direct Energy Marketing Limited (a public resource company).
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 of Pine Cliff Energy Ltd.
Rodger A. Tourigny (Chairman)	• B. Com., C.A., private investor and financial consultant. • Director of several public corporations and a member of the audit committee of certain of these corporations. • 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
2017	$155,000	$89,000	$ -	$ -
2016	$180,000	$118,000	$ -	$ -

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, 2017, 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, 2018. 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, 2017 and 2016, which are included in Bonterra's Annual Report for the year ended December 31, 2017.

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 4th 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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, 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, 2017**	**Canada**	**Nil**	**1,344,990**	**Nil**	**1,344,990**

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, 2017)"

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
January 31, 2018

(signed) "Douglas O. McNichol., P. Eng"
Manager, Engineering

(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, 2017, 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) "Rodger A. Tourigny"
Rodger A. Tourigny, Director

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

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

March 13, 2018

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.