BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2022

March 9, 2023

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The information in this AIF is given as of December 31, 2022 unless otherwise indicated.

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 twelve month period;

"Shareholder" means a holder of Bonterra common shares;

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

"Sproule Report" means the independent engineering evaluation of Bonterra's oil, natural gas and NGLs interests prepared by Sproule dated February 7, 2023 and effective December 31, 2022 utilizing the average commodity price forecasts of Sproule, GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd. dated December 31, 2022; and

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

ABBREVIATIONS

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

Other

AECO	means Alberta Energy Company interconnect with the NOVA System.
BOE	means barrel of oil equivalent. In all cases of this document, a BOE conversion ratio for natural gas of 6 Mcf:1Bbl has been used. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading, particularly if used in isolation.
MBOE	means thousand BOE.
BOE/d	means BOE per day.
WTI	means West Texas Intermediate at Cushing, Oklahoma, the benchmark crude oil for pricing purposes.
GCA	means gas cost allowance deduction taken off of provincial (Crown) royalties, to offset the capital and direct operating costs associated with processing the Crown's share of raw gas at a gas plant and transporting the Crown's share of residue gas through a sales line.

CONVERSIONS

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

To convert from	To	Multiply By
Mcf	Cubic Metres	28.174
Cubic Metres	Cubic Feet	35.494
Bbl	Cubic Metres	0.159
Cubic Metres	Bbl	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

ADVISORY

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

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

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

PRESENTATION OF OIL AND GAS INFORMATION

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

DEFINITIONS AND NOTES TO RESERVE DATA TABLES

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

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

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

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

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

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

1. Proved Reserves

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

2. Probable Reserves

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

3. Possible Reserves

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

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

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

4. Developed Reserves

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

5. Developed Producing Reserves

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

6. Developed Non-Producing Reserves

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

7. Undeveloped Reserves

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

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

8. Levels of Certainty for Reported Reserves

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

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

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

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

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

CURRENCY

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

FORWARD-LOOKING STATEMENTS

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

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

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

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

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

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

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

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

STRUCTURE OF BONTERRA ENERGY CORP.

Bonterra Energy Corp.

Bonterra Energy Corp. ("Bonterra" or "the Company") is an 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.

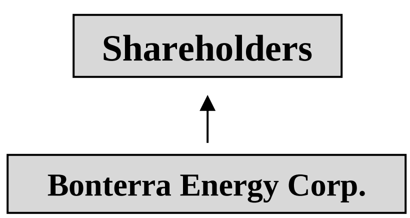
The Company's primary focus is to maximize total return to shareholders by moderately growing production, debt reduction and returning to a sustainable cash dividend model through the optimum utilization and development of existing crude oil and natural gas properties and acquisition and development 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 1230, 300 5th Ave SW Calgary, Alberta T2P 3C4

Organization Chart

At December 31, 2022, 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 2022, 2021 and 2020

There was no material acquisitions or dispositions for the years ending December 31, 2020, December 31, 2021 and December 31, 2022.

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, 2022 contained in the Sproule Report dated February 7, 2023.

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, 2022 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, 2022
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	18,072.0	15,850.9	77,590	71,378	2,698.7	2,245.9	33,702.3	29,993.1
Developed Non-Producing	2,402.8	2,161.1	6,971	6,473	234.3	199.0	3,798.9	3,439.0
Undeveloped	22,699.4	19,422.2	99,792	90,981	3,869.2	3,327.7	43,200.6	37,913.4
TOTAL PROVED	43,174.2	37,434.1	184,352	168,833	6,802.3	5,772.6	80,701.8	71,345.5
PROBABLE	10,399.9	8,190.8	46,168	41,102	1,693.5	1,332.4	19,788.1	16,373.5
TOTAL PROVED PLUS PROBABLE	53,574.1	45,624.9	230,520	209,935	8,495.9	7,104.9	100,489.9	87,719.0

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, 2022
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	921.6	768.1	632.1	537.7	470.8	21.08
Developed Non-Producing	133.2	79.4	55.8	42.6	34.3	16.23
Undeveloped	1,094.4	692.7	468.0	331.9	243.6	12.34
TOTAL PROVED	2,149.2	1,540.2	1,155.9	912.3	748.8	16.20
PROBABLE	782.7	469.0	325.7	247.3	198.6	19.89
TOTAL PROVED PLUS PROBABLE	2,931.9	2,009.2	1,481.6	1,159.7	947.4	16.89

(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, 2022
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	753.3	647.1	538.7	462.0	407.2
Developed Non-Producing	105.9	61.6	42.9	32.6	26.1
Undeveloped	839.9	520.4	340.7	232.1	162.3
TOTAL PROVED	1,699.1	1,229.1	922.3	726.9	595.7
PROBABLE	605.6	361.7	250.8	190.3	152.7
TOTAL PROVED PLUS PROBABLE	2,304.8	1,590.8	1,173.1	917.2	748.4

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(b)
TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2022
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	5,916.9	746.8	2,133.5	660.0	227.2	2,149.1	450.0	1,699.1
PROVED PLUS PROBABLE	7,510.4	1,042.0	2,640.1	660.0	236.3	2,931.8	627.0	2,304.7

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(c)
NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2022
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)	1,132.1	16.70
	Conventional Natural Gas (Including associated by-products)[2]	23.7	6.71
Total		1,155.9	
Proved Plus Probable	Light And Medium Crude Oil (Including solution gas and associated by-products)	1,447.7	17.38
	Conventional Natural Gas (Including associated by-products)[2]	33.9	7.69
Total		1,481.6	

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

The Company only operates in Canada.

PART III – PRICING ASSUMPTIONS

<u>Forecast Prices</u>
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 Pentanes Edmonton ($Cdn/bbl)	NGL Butanes Edmonton ($Cdn/ bbl)	NGL Propane Edmonton ($Cdn/ bbl)	Operating Cost Inflation Rate (%/Yr)	Capital Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
HISTORICAL								
2018	68.49	1.53	79.31	33.65	27.00	2.00	4.00	0.77
2019	68.87	1.80	71.39	23.71	17.16	(1.00)	-	0.75
2020	45.39	2.24	49.85	21.87	16.31	(5.0)	(5.0)	0.75
2021	80.31	3.64	85.88	51.64	43.39	4.00	8.00	0.80
2022	119.73	5.43	121.28	61.68	50.11	9.00	11.00	0.77
FORECAST(1)(2)								
2023	103.76	4.23	106.22	53.88	39.80	-	-	0.75
2024	97.74	4.40	101.35	52.67	39.14	2.33	2.33	0.77
2025	95.27	4.21	98.94	51.42	39.74	2.00	2.00	0.77
2026	95.58	4.27	100.19	51.61	38.86	2.00	2.00	0.77
2027	97.07	4.34	101.74	52.39	40.47	2.00	2.00	0.78
2028	99.01	4.43	103.78	53.44	41.28	2.00	2.00	0.78
2029	100.99	4.51	105.85	54.51	42.11	2.00	2.00	0.78
2030	103.01	4.60	107.97	55.60	42.95	2.00	2.00	0.78
2031	105.07	4.69	110.13	56.71	43.81	2.00	2.00	0.78
2032	106.69	4.79	112.33	57.56	44.47	2.00	2.00	0.78
2033	108.83	4.88	114.58	58.71	45.35	2.00	2.00	0.78

(1) Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.
(2) The forecasted of product prices is an average of independent reserve evaluators Sproule, GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd.

The Company's weighted average realized prices by production type for the 2022 financial year are as follows:

Light and Medium Crude Oil ($ per barrel)	113.93
Conventional Natural Gas ($ per Mcf)	5.44
Natural Gas Liquids ($ per barrel)	66.00

PART IV – RECONCILIATION OF CHANGES IN RESERVES

RECONCILIATION OF COMPANY GROSS RESERVES (BEFORE ROYALTY) BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS

	Light and Medium Crude Oil (MBbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
PROVED				
December 31, 2021	**43,470.4**	**166,795**	**6,961.7**	**78,231.2**
Discoveries	-	-	-	-
Extensions[1]	4,346.9	12,741	572.8	7,043.0
Technical Revisions	(4,701.1)	7,797	(618.4)	(4,019.9)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	2,647.8	8,342	302.8	4,341.0
Production	(2,589.7)	(11,323)	(416.6)	(4,893.6)
December 31, 2022	**43,174.2**	**184,352**	**6,802.3**	**80,701.8**
PROBABLE				
December 31, 2021	**10,760.2**	**40,478**	**1,693.5**	**19,200.2**
Extensions[1]	1,043.7	3,072	138.7	1,694.3
Technical Revisions	(1,548.0)	2,340	(153.6)	(1,311.6)
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	144.0	278	14.8	205.1
Production	-	-	-	-
December 31, 2022	**10,399.9**	**46,168**	**1,693.5**	**19,788.1**
PROVED PLUS PROBABLE				
December 31, 2021	**54,230.6**	**207,273**	**8,655.3**	**97,431.4**
Extensions[1]	5,390.6	15,812	711.5	8,737.5
Technical Revisions	(6,249.1)	10,137	(771.9)	(5,331.6)
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	2,791.8	8,620	317.6	4,546.2
Production	(2,589.7)	(11,323)	(416.6)	(4,893.6)
December 31, 2022	**53,574.1**	**230,520**	**8,495.9**	**100,489.9**

(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
2020	1,185	22,877	0	77,005	155	3,794	1,340	39,505
2021	2,338	22,613	10,115	93,315	409	4,008	4,439	42,173
2022	4,212	22,699	12,162	99,792	547	3,869	6,786	43,200

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
2020	316	6,147	0	20,103	42	989	358	10,486
2021	608	5,731	2,608	23,456	106	1,009	1,149	10,648
2022	1,009	5,681	2,922	24,957	132	965	1,629	10,805

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

Sproule's evaluation of Bonterra's reserves as of December 31, 2022 is in accordance with the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook").

Bonterra's proved undeveloped reserves amount to 43,201 MBOE and represent approximately 53.5 percent of the total proved reserves and 43.0 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 has extensive Proved development opportunities that are prioritized based on a disciplined set of criteria including but not limited to, investment payouts and rates of return, land maturities, the optimization of facility infrastructure and development, and marketing commitments. With this extensive portfolio of opportunities, it is prudent to balance cash flows and other corporate resources to optimize asset values, rather than completely execute the development of the entire portfolio of booked opportunities within two years. Approximately 29.2 percent of the Proved development spending occurs within a two-year timeframe.

The development schedule of these reserves has been based on recent and current capital activity levels, with no material deferrals of development opportunities beyond normal prudent budgetary considerations. Approximately half of the Proved Undeveloped reserves are planned to be on stream within a three-year timeframe, representing approximately 53 percent of the net undeveloped location count, as well as 49 percent of the net total future development capital. These development activities are directed almost entirely to the Company's core focus areas in the Pembina and Willesden Green fields in Alberta, Canada.

Bonterra's probable undeveloped reserves amount to 10,805 MBOE and represent approximately 10.8 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.

Bonterra's proved plus probable undeveloped reserves are primarily comprised of Cardium horizontal locations.

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 2022 Annual Report.

Future Development Costs

$ 000s	Prices and Costs	
Year	Proved	Proved Plus Probable
2023	103,827	103,827
2024	88,933	88,933
2025	132,466	132,466
2026	172,581	172,581
2027	162,290	162,290
Total Undiscounted	660,097	660,097

The above future development costs will be funded primarily from 2023 to 2027 cash flow from operations 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

All of Bonterra's oil and natural gas properties are primarily located in the Province of Alberta. The Company also has non-core properties located in the Provinces of Saskatchewan and British Columbia. In 2022, production volumes from Bonterra's properties were approximately 61 percent light and medium crude oil and NGLs and 39 percent conventional natural gas on a BOE basis. During the year ended December 31, 2022, Bonterra's oil and natural gas properties yielded average annual production of 13,407 BOE per day (2021 – 12,747 BOE per day, 2020 – 10,575 BOE per day). As at December 31, 2022 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 100,489 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 99.1 percent of Proved plus Probable reserves.

The Pembina Cardium field is the largest conventional oil field in Canada with an estimate of original oil in place (OOIP) of 10.6 billion barrels with less than 15 percent produced to date. This field has proved to be a significant area for multi-zone oil and natural gas exploration with predictable results. Horizontal drilling with multistage fracking drastically improves recoveries from areas developed with vertical drilling and extends the economic edge of the reservoir where vertical drilling is not economic. Bonterra operates approximately 93 percent of its production and operates the majority of its related oil and gas processing facilities.

The Company invested capital expenditures of $79.8 million in 2022. Of the total capital invested $56.7 million was directed to drilling 25 gross (24.7 net) operated wells and completing, equipping, tying-in and placing on production 31 gross (30.7 net) horizontal wells in the Cardium formation with a 100 percent success rate. Six of the wells tied and completed in 2022 were drilled in 2021. The Company also invested approximately $6.1 million of the capital program to the construction of a wholly owned gas plant to resolve gas handling issues, and an additional $17.0 million was directed to related infrastructure, recompletions and non-operated capital programs.

Facilities

Bonterra operates approximately 50 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 four gas plants the Company operates or other non-operated gas plants, most of which Bonterra has ownership in.

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. Average annual production for 2022 was 87 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 average annual production of approximately 32 BOE per day for 2022. The Company is currently restricted due to a third-party sales line failure that has resulted in approximately 153 BOE per day of shut-in production for 2022. The third-party sales line failure is not expected to be remedied in 2023.

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, 2022 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	1,203	828.0	117	26.4	481	243.4	50	20.6	1,684	1,071.4	167	47.0
BC	-	-	28	17.4	-	-	49	9.8	-	-	77	27.3
SK	27	18.0	-	-	11	6.6	-	-	38	24.6	-	-
Total	1,230	846.0	145	43.8	492	250.1	99	30.5	1,722	1,096.1	244	74.3

Properties with No Attributable Reserves

Bonterra's properties with no attributable reserves consist of approximately 102,656 gross and 73,559 net undeveloped acres, of which 1,760 acres are subject to work commitments in 2023.

Expiring acreage in the next twelve months consists of 972 gross (972 net) acres. The Company will continue to maximize their value until they have expired.

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

Financial Risk Management

The Company uses various financial risk management contracts to manage commodity price risk, including physical delivery sales and risk management contracts to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided to enter into commodity price agreements. These contracts can amount to fifty percent of the Company's daily crude oil production or thirty percent of its total daily production at certain points during a quarter.

Additional Information Concerning Abandonment and Reclamation Costs

In connection with its operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Company budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. The Company estimates such costs through a model that incorporates data from the Company's operating history, industry sources and cost formulas used by Alberta Energy Regulator, together with other operating assumptions. The Company expects all of its net wells to incur these costs. The Company anticipates the total amount of such costs, excluding inflation, to be approximately $178,183,000 ($387,020,000 including inflation) on an undiscounted basis and $21,446,000 with inflation at approximately 2% and 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 includes approximately $36,644,000 on an undiscounted basis and $936,000 discounted at 10% as these amounts represent cost for abandonment and reclamation of future wells and facilities that the obligation has not occurred. The calculations of future net revenue associated with proved plus probable developed reserves under "Oil and Natural Gas Reserves" in this Annual Information Form excludes approximately $187,307,000 on an undiscounted basis (including inflation) and $9,367,000 discounted at 10% as these amounts represent cost for abandonment and reclamation of facilities and wells for which no reserves have been attributed and future abandonment and reclamation costs on obligations that have not occurred. In the next three years financial years, the Company anticipates that a total of approximately $17,350,000 on an undiscounted basis and $14,656,000 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	60,770
Share issue costs	20	6,804
Canadian oil and gas property expenditures	10	66,255
Canadian development expenditures	30	97,113
Canadian exploration expenditures	100	8,587
		239,529

The Company has $5,761,000 (December 31, 2021 - $8,861,000) of investment tax credits that expire in the following years; 2025 - 477,000; 2026 - $2,405,000; 2027 - $2,009,000; 2028 - $745,000; 2034- $99,000 and 2037-$26,000.

The Company has $64,725,000 (December 31, 2021 - $64,725,000) 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)	2022	2021
Land	2,569	1,621
Exploration and development costs	77,200	65,661
Net petroleum and natural gas capital expenditures	79,769	67,282

Exploration and Development Activities

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

	2022					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	34.0	25.8	-	-	34.0	25.8
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	34.0	25.8	-	-	34.0	25.8
Success rate	100%	100%	-	-	100%	100%

	2021					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	39.0	35.8	-	-	39.0	35.8
Natural gas wells	-	-	-	-	-	-
Dry wells	-	-	-	-	-	-
Total	39.0	35.8	-	-	39.0	35.8
Success rate	96%	96%	-	-	96%	96%

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

Production Estimates 2023

	2023			
	Light and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (Bbl/d)	Total (BOE/d)
Alberta[1]	8,505	41,727	1,484	16,945
British Columbia	-	143	2	26
Saskatchewan	69	-	-	69
	8,574	41,869	1,486	17,040

[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 2022

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	7,356	110.41	8.91	25.21	76.29
2 Quarter	7,623	126.97	13.78	23.24	89.95
3 Quarter	6,649	111.44	15.16	32.79	63.49
4 Quarter	6,764	105.59	12.79	24.68	68.12
Conventional Natural Gas (Mcf)					
1 Quarter	29,609	4.80	1.49	0.99	2.32
2 Quarter	33,323	6.76	2.30	0.97	3.49
3 Quarter	31,052	4.73	2.53	0.90	1.30
4 Quarter	30,101	5.36	2.13	0.87	2.36
Natural Gas Liquids (Bbl)					
1 Quarter	996	63.02	8.91	14.46	39.65
2 Quarter	1,151	77.23	13.77	20.11	43.35
3 Quarter	1,206	64.45	15.16	15.71	33.58
4 Quarter	1,209	59.38	12.79	13.37	33.22

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

	2022 Light and Medium Crude Oil and NGL (Bbl per day)	Conventional Natural Gas (Mcf per day)	Total (BOE per day)
Alberta	8,151	30,823	13,288
Saskatchewan	81	34	87
British Columbia	4	166	32
	8,236	31,023	13,407

Lease Holdings

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

	2022		2021	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	345,924	218,640	331,252	204,134
Saskatchewan	586	3,677	7,806	5,595
British Columbia	65,913	28,297	65,913	28,260
	412,423	250,614	404,970	237,989

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, debt reduction and potentially returning to 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

Bonterra historically paid monthly dividends, prior to the onset of the COVID-19 pandemic. On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing on April 1, 2020. The Company is planning to implement a dividend model by the end of 2023.

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, director and officer liability and business interruption.

Borrowing

The Company’s debt obligations consist of a bank facility, a subordinated term debt and subordinated debentures. Details of the banking arrangement is contained in Note 8 of Bonterra's audited annual financial statements for the year ended December 31, 2022, contained in the Company’s 2022 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 39 persons and contracted numerous office and field operations personnel.

INDUSTRY CONDITIONS

Production and Operation Regulations

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

Pricing and Marketing in Canada

Crude Oil

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

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("OPEC") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's COVID restrictions. OPEC predicts global oil demand to rise by 2.32 million barrels per day in 2023, despite interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russia launched a large scale invasion of Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict between these nations remains uncertain.

Natural Gas

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

Natural Gas Liquids

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

Exports from Canada

In 2019, the National Energy Board (the "NEB") was replaced with the Canadian Energy Regulator (the "CER"). The CER's governing legislation is the Canadian Energy Regulator Act ("CERA") and the Impact Assessment Act (the "IAA"). The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL from Canada.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the National Energy Board Act Part VI (Oil and Gas) Regulation (the Part VI Regulation) until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

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

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints, Pipeline Capacity and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors.

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

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

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

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, experienced permitting difficulties in the United States and completion of the United States portion of the pipeline replacement was delayed following the announcement that the Minnesota Pollution Control Agency would require a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals declared that the Minnesota Utilities Commission correctly granted Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court refused to hear an appeal on this matter.

After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and is expected to transport 760,000 barrels per day at full capacity.

In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota, rather than downstream concerns like GHG emissions from the ultimate burning of the crude oil carried in the pipeline.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the Federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the Trans Mountain Pipeline system. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the federal government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and the Supreme Court of Canada ("SCC") in July 2020.

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

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and mechanical completion of the project is expected to occur in the third quarter of 2023.

TC Energy Corporation's ("TC Energy") Keystone XL Pipeline was expected to begin construction in the first half of 2019, but pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final supplemental environmental impact statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility.

While construction on the Keystone XL Pipeline started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits and on April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States (Nationwide Permit 12). The United States Court of Appeals for the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined that the reinstatement would not apply to the Keystone XL Pipeline.

On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which has overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation, and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan (the "U.S. District Court") rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. In February 2023, the U.S. District Court granted a motion that would enable Michigan's Attorney General to appeal the August 2022 decision.

The Oil Tanker Moratorium Act, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban effectively prevents pipelines being built to, and export terminals being located on, the coast of British Columbia at any point north of Vancouver Island.

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program would be cancelled by assigning the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "NGTL System") and the expanded NGTL System was completed in April 2022.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the CGL Pipeline). Pre-construction activities began in November 2018, with a planned completion target of 2025. In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline. The CGL Pipeline is currently 80% complete and is slated to have a mechanical in-service date by the end of 2023.

Woodfibre LNG Limited issued a notice to proceed with construction of the Woodfibre LNG project to its prime contractor in April 2022. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Major construction is set to commence in 2023, with substantial completion of the project expected in late 2027. In November 2022, Enbridge Inc. completed a transaction with Pacific Energy Corporation Limited, the owner of Woodfibre LNG Limited, to retain a 30% ownership stake in the project.

In addition to LNG Canada, the CGL Pipeline and the Woodfibre LNG project, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

NAFTA/USMCA and Other Trade Agreements

The North American Free Trade Agreement ("NAFTA") that previously existed among the governments of Canada, the United States and Mexico has been replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "USMCA") and sometimes referred to as the Canada United States Mexico Agreement or CUSMA. The USMCA came into force on July 1, 2020. Because the United States remains Canada’s primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, the implementation of the USMCA could have an impact on Western Canada’s petroleum and natural gas industry at large, including the Company's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union (Brexit) on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("CUKTCA"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and ten other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (CPTPP) on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, and Peru. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

While it is uncertain what effect CETA, CPTPP, CUKTCA 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.

Extractive Sector Transparency Measures Act

On June 1, 2015, the federal government's Extractive Sector Transparency Measures Act (the "ESTMA") came into effect, which imposed mandatory reporting requirements on payments to government. ESTMA contains broad reporting obligations with respect to payments to governments and state-owned entities, including employees and public office holders, made by Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state-owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected constitutes a separate offence.

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, usually from two to five years for oil and natural gas leases, and usually 15 years for Alberta bitumen leases. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

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

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

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

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the Indian Act (Canada). Indian Oil and Gas Canada ("IOGC"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

Royalties and Incentives

General

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

Occasionally the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low to encourage exploration and development activity. Additional programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

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

Alberta - Royalties

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

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of Modernized Royalty Framework for Alberta (MRF). The MRF formally took effect on January 1, 2017 for new wells drilled after this date. The previous royalty framework (the "Old Framework") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. On July 12, 2016, the Government of Alberta announced that producers could apply for early adoption of the MRF in respect of wells spud between July 13, 2016 and December 31, 2016. As of January 1, 2027, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

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 of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines.

As the 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 percent. Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40 percent for pentanes and 30 percent for butanes and propane.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner.

Freehold mineral taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4 percent of revenues reported from freehold mineral title properties. Freehold mineral taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

Saskatchewan - Royalties

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

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

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a 5-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based GHG emissions by 40 to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan also has a drilling incentive whereby qualifying incentive volumes of newly drilled oil wells are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

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

British Columbia - Royalties

In May 2022, the government of British Columbia introduced a new royalty framework that is set to come into effect September 1, 2024 with a two-year transition period beginning on September 1, 2022. The new royalty framework will be based on a revenue-minus cost royalty system with price-sensitive royalty rates designed to reflect the value of the resource and achieve a return of 50% of profits after production costs are accounted for. New wells will pay a flat royalty of 5% until the capital spent on drilling and completions is recovered, following which, the well will move to a price-sensitive royalty rate between 5% and 40%. The range of the rate will vary by commodity type. During the transition period, any new wells which are spud on or after September 1, 2022 are not eligible for the deep-well royalty program, the marginal well royalty program or the ultra-marginal royalty program. Wells that are spud on or after September 1, 2022 will pay a 5% royalty rate for the equivalent of the first 12 production months, following which the wells will pay royalties based on the current royalty framework until September 1, 2024 when all the wells transition to the new framework.

Wells drilled prior to September 1, 2022 shall continue to pay royalties based on the current royalty framework until the new framework takes effect on September 1, 2024. The royalties payable by producers in British Columbia will vary depending on the types of wells and the characteristics of the substances being produced.

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

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

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

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

The Ministry of Energy, Mines and Low Carbon Innovation intends to create a mechanism that will begin in early 2023 to allow producers to repurpose unused deep well entitlements by transferring them to a Healing Land and Emission Reduction Pool. Once allocated to a producer's pool, the deep well credits will no longer be available to reduce royalties on the well they were originally allocated to.

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

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

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

Federal

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

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

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Government of Alberta, supported by the governments of Ontario and Saskatchewan, has challenged the constitutionality of the IAA and requested that the federal legislation be invalidated by the Alberta Court of Appeal on the basis that it encroaches on provincial jurisdiction. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal Government has appealed the Alberta Court of Appeal's opinion to the SCC. A date for arguments has not been scheduled, but filing deadlines have been set for early 2023.

On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada’s response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada.

Alberta

The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge in the event that they are not covered by Bonterra’s insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. 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.

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the Responsible Energy Development Act and a number of related statutes including the *Oil and Gas Conservation Act* (the "OGCA"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Land and Property Rights Tribunal, as well as Alberta Energy's responsibility for mineral tenure.

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

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effect management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in Subsurface Order Nos. 2, 6 and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the Seismic Protocol Regions). Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Saskatchewan

The Saskatchewan Ministry of the Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. The Oil and Gas Conservation Act (the "SKOGCA") is the statute governing the regulation of resource development operations in the province, along with The Oil and Gas Conservation Regulations, 2012 and The Petroleum Registry and Electronic Documents Regulations. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as a partner in the Petrinex Database. The Petrinex Database delivers business processes and information required for the assessment, levy, and collection of crown royalties for Alberta, Saskatchewan, Manitoba and British Columbia. It provides information in support of the regulatory mandates and legislation of the provinces, and services that facilitate important industry commercial activities, including partner to partner reporting, oil marketing, financial analytics, compliance assurance and production accounting.

British Columbia

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

In November 2022, the Government of British Columbia passed the Energy Statutes Amendment Act, 2022 (the "ESA Act"). The ESA Act will change the name of the BC OGC to the British Columbia Energy Regulator, and its mandate will be expanded to include oversight of hydrogen, ammonia and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the Energy Resource Activities Act (the "ERAA"). In addition to expanding the British Columbia Energy Regulator's jurisdiction to include hydrogen, ammonia and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to crude oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The Drilling and Production Regulation requires a producer to suspend its operations if they trigger a seismic event with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the Kiskatinaw Area). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the seismic event and developing an approved protocol for subsequent events, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. Future seismic events outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

On November 28, 2019, the Declaration on the Rights of Indigenous Peoples Act (the DRIPA) became law in British Columbia. The DRIPA aims to align British Columbia's laws with the United Nations Declaration of the Rights of Indigenous Peoples; however, it is unclear what the practical consequences of this law will be.

An updated Environmental Assessment Act came into force in December of 2019. The amendments subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process, as well as enhance indigenous engagement in the project approval process with an emphasis on consensus-building in alignment with the DRIPA. Simultaneously with the enactment of the Environmental Assessment Act, the British Columbia Government enacted the accompanying Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Liability Management Rating Programs

Alberta

The AER oversees closure requirements, including the abandonment and reclamation of wells, well sites, facilities, facility sites, and pipelines. Historically, the AER discharged this role through its Liability

Management Rating Program (the "AB LMR Program"). The AB LMR Program relied on the ratio of a company's assets and liabilities (the "Liability Management Ratio" or "LMR") to assess whether the company would be able to address closure obligations. Where a company's liabilities exceeded their assets (resulting in a Liability Management Ratio of less than 1.0), the AER could require the company to post security to bring the ratio to 1.0. The AB LMR Program was developed during a period of rapid growth in the province when companies were focused on well and infrastructure expansion. In recent years, it became clear that the AB LMR Program needed to be updated to reflect declining production and aging infrastructure.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association* v *Grant Thornton* (also known as the "Redwater" decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the Liabilities Management Statutes Amendment Act, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the orphan fund ("Orphan Fund") established under the OGCA to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

As a result of the changing landscape and new direction from the Redwater decision, in July 2020, the Government of Alberta began implementing changes to its liability management policy. In particular, in July 2020, the Government of Alberta released a new Liability Management Framework ("AB LMF") which includes a series of mechanisms and requirements to improve and expedite reclamation efforts and to require industry to better manage clean-up of oil and gas wells, pipelines and facilities. Notably, the AB LMF provided policy direction allowing the AER to take "Licensee Special Action" to assist operators in managing their assets and maintaining operations under certain circumstances. The AB LMF also confirmed that the previous Liability Management Ratio that existed under the AB LMR Program would be replaced with a new "Licensee Capability Assessment System" that provides a more comprehensive assessment of a Licensee's ability to meet its regulatory obligations. Finally, the AB LMF introduced the "Inventory Reduction Program", whereby the AER would establish individual and industry-wide targets for closure activity in order to help reduce inactive well and facility inventories.

The Government of Alberta followed the announcement of the AB LMF with amendments to the Oil and Gas Conservation Rules and the Pipeline Rules in late 2020. The changes to these rules fall into three broad categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

The AB LMF provided Government of Alberta policy direction on managing energy sector closure requirements. The AER implements and administers that policy through directives. In April 2021, the AER made changes to Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("Directive 067") in order to increase scrutiny the AER applies to ensure that authorization for oil and gas development is only granted to responsible parties. Those changes include additional requirements for industry to provide updated financial information when making certain applications to the AER and throughout the energy development lifecycle. As a result of the changes to Directive 067, the AER may revoke or restrict a company's eligibility to hold AER licenses if the AER determines that the licensee poses an "unreasonable risk", taking into account a broad range of financial and operational considerations.

On December 1, 2021, the AER published a new Directive 088: Licensee Life-Cycle Management ("Directive 088") and supporting guidance information to further support implementing the AB LMF. Among other things, Directive 088 establishes the AER's authority to conduct a holistic licensee assessment to inform regulatory decisions about a given licensee, including by conducting a "Licensee Capability Assessment." Directive 088 also establishes the "Licensee Management Program" contemplated in the AB LMF which enables the AER to proactively monitor licensees to identify those at risk of not meeting their regulatory obligations and to use appropriate regulatory tools to address that risk. Finally, Directive 088 establishes the Inventory Reduction Program and allows the AER to set licensee-specific and industry-wide closure targets.

Complementing the AB LMF program and associated directives, Alberta's OGCA establishes the Orphan Fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LMR Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be funded by licensees in the AB LMR Program who contribute to a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences for large facilities. Collectively, these programs, the AB LMF, and associated directives are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In addition, to address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("ABC") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "SK LLR Program"), which was updated in January 2023. The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "Oil and Gas Orphan Fund") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, a licence transfer application must be completed through the Integrated Resource Information System ("IRIS"). An assessment is conducted on both the transferee and the transferor listed in the IRIS application. To complete the assessment, both a licensee liability rating ("LLR") assessment and a proportional risk transfer is conducted. If a licence transfer will result in either the transferor or transferee having an LLR of less than 1.0, the transferor or transferee, as applicable, must submit the amount of security deposit required by the minister.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new Financial Security and Site Closure Regulations (the "Closure Regulations"), which came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012 (the "Conservation Regulations") remain in effect. Among other things, the Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

British Columbia

The B.C. Commission previously oversaw a Liability Management Rating Program (the "BC LMR Program"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. In 2019, the BC Commission introduced a Comprehensive Liability Management Plan (CLMP). The purpose of the CLMP is to ensure that 100% of the costs associated with the reclamation of oil and natural gas sites is paid by industry, rather than the Government of British Columbia or residents of British Columbia. Pursuant to the CLMP, the BC Commission is implementing a Permittee Capability Assessment (PCA) program. Similar to the framework to be implemented in Alberta, the PCA program is intended to be a holistic evaluation of permittees throughout the development life cycle and is intended to replace the BC LMR Program. The PCA program is intended to mitigate risk and minimize pressure on the Orphan Site Reclamation Fund.

In 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("OSRF") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the Dormancy and Shutdown Regulation (the "Dormancy Regulation") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to $100 million of an existing $235 million loan to the Orphan Fund. In Saskatchewan, $400 million in federal funding was used for the Accelerated Site Closure Program (“ASCP”). The first phase of the ASCP made $100 million available to eligible service companies to conduct abandonment and reclamation work. The ASCP is in the final year of operation, with the program ending in the spring of 2023. In July 2022, the ASCP opened application processes to release all remaining ASCP funding to eligible licensees.

Climate Change Regulation

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

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "UNFCCC") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with Canada's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the "2030 Reduction Plan"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050.

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The Canadian Net-Zero Emissions Accountability Act became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of CO_2e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. In accordance with the 2030 Reduction Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO_2e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards (the federal benchmark) for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the Supreme Court of Canada and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in Reference re Greenhouse Gas Pollution Pricing Act, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards. Currently the federal fuel charge applies in each of Ontario, Manitoba, Yukon, Alberta, Saskatchewan and Nunavut while the output based pricing system applies in Manitoba, Prince Edward Island, Yukon, Nunavut and partially in Saskatchewan. The provincial plans for each of Nova Scotia, Prince Edward Island and Newfoundland and Labrador were deemed by the federal government to have fallen short of the federal benchmark, making the federal OBPS applicable in each of those provinces as of July 1, 2023. For so long as the provincial systems in Alberta (under the Technology Innovation and Emissions Reduction (TIER) regulation) and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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

As part of its efforts to provide relief to Canada’s petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

The federal government has also announced that it will proceed with the development and implementation of a Clean Fuel Standard (CFS) that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed CFS regulations, with the Clean Fuel Regulations (CFS Regulations) coming into force on June 21, 2022. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement will start at 3.5 g CO2e/MJ, increasing by 1.5 gCO2e/MJ each year and reaching 14 gC02e/MJ in 2030. The standard will apply to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "CLP"). Under this strategy, the Climate Leadership Act (the "CLA") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions. In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime (CCIR) remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $50/tonne and will increase to $65/tonne on April 1, 2023. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulation.

The provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the Technology Innovation and Emissions Amendment Regulation was adopted with certain amendments to the TIER Regulation becoming effective January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for CCUS projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO2e to 2,000 tonnes of CO2e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. As discussed above, the TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the Methane Emission Reduction Regulation (the Alberta Methane Regulations) on January 1, 2020, and the AER simultaneously released an updated edition of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting. The release of Directive 060 complements a previously released update to Directive 017: Measurement Requirements for Oil and Gas Operations that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations. In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply once the agreement is effective.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors and reduce GHG emissions by 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010, which deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced The Management and Reduction of Greenhouse Gases Act (the "MRGGA") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030. The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework. As noted above, the federal fuel charge applies in Saskatchewan and the system implemented by the MRGGA currently meets the federal stringency requirements for the emissions it covers and the federal backstop applies for those emissions which are not covered.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations, and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the Saskatchewan O&G Emissions Regulations) came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, Bill 147 – An Act to amend The Oil and Gas Conservation Act, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $40/tonne of CO2e. While the scheduled increase to $45/tonne of CO2e was delayed until October 1, 2020 in response to COVID-19, the Government of British Columbia announced on September 2, 2020 that the increase would not take place until April 1, 2021. On April 1, 2021, B.C.'s carbon tax rate rose from $40/tonne to $45/tonne per CO2e and was increased again on April 1, 2022 to $50 per tonne of CO2e. As noted above, the pollution pricing system in British Columbia currently meets the federal stringency requirements and in order to maintain its application, the fuel charge will increase to $65/tonne of CO2e in 2023 to maintain compliance with the federal benchmark.

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

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of oil and gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. On July 6, 2021, the Government of British Columbia released the B.C. Hydrogen Strategy, which lays out a framework for the province to utilize hydrogen in support of its CleanBC plan. The Strategy sets out 63 actions to be undertaken over three periods of time: (i) short term (2020-2025), (ii) medium term (2025-2030), and (iii) long term (2030-beyond).

On January 16, 2019, the B.C. Commission announced a series of amendments to the B.C. *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia. The equivalency agreement will be in place for a period of 5 years.

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

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

Volatility in the Oil and Gas Industry

Market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC and non-OPEC countries, sanctions against Russia, Iran and Venezuela, slowing growth in China and emerging economies, concerns over public health related events and the impact that it will have on the supply of and demand for oil and gas, market volatility and disruptions in Asia, weakening global relationships, conflict between Ukraine and Russia and the U.S. and Iran, isolationist trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors - Political Uncertainty*". These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation, see "*Royalties and Incentives*", "*Regulatory Authorities and Environmental Regulation*" and "*Climate Change Regulation*" in "*Industry Conditions*". In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the crude oil and natural gas industry in Western Canada have at times led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has at times created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada (see "*Industry Conditions - Transportation Constraints, Pipeline Capacity and Market Access*").

A decline in commodity prices may affect the volume and value of the Company's reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices may 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 (see "*Risk Factors – Credit Facility Arrangements*"). 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.

Adverse Economic Conditions

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect the Company by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing the Company's supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in operations, and (iii) affecting the health of the Company's workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere herein that affect the supply and demand for crude oil, NGLs and natural gas, and the Company's business and industry, could ultimately have an adverse impact on the Company's financial condition, financial performance, and funds flow.

Commodity Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired, discovered or produced by Bonterra is, and will continue to be, affected by numerous factors beyond its control. The Company's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets or contract for the delivery of crude oil by rail. (see "*Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access*" and "*Risk Factors" - Weakness and Volatility in the Oil and Natural Gas Industry*"). The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines, processing and storage facilities; and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East, Ukraine and Taiwan and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of Bonterra's anticipated net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. Bonterra might also elect not to produce from certain wells at lower prices.

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See "*Weakness and Volatility in the Oil and Natural Gas Industry*".

All of these factors could result in a material decrease in Bonterra's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business and financial condition.

In addition, bank borrowings available to Bonterra may, in part, be determined by its borrowing base. A sustained material decline in prices from historical average prices could reduce Bonterra's borrowing base, therefore reducing the bank credit available which could require that a portion, or all, of Bonterra's bank debt be repaid.

Title to and Right to Produce from Assets

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

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

Volatility of Market Price of Common Shares

The trading price of securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of commodities has increased due to, in part, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in crude oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities.

Similarly, the market price of 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. Accordingly, the price at which the Common Shares 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 approvals on 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 its oil and gas reserves.

Bonterra's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect Bonterra's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and funds from operations.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Bonterra's production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase Bonterra's costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Bonterra is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where Bonterra is currently conducting, or in the future plans to conduct operations, Bonterra may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, Bonterra's fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Bonterra is ultimately able to produce from its reserves.

Disposal of Fluids Used in Operations

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

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 potentially available 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 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.

Variations in Foreign Exchange Rates and Interest Rates

Operating costs incurred by Bonterra are generally paid in Canadian dollars. World crude oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar negatively impact Bonterra's production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Bonterra's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Bonterra may contract.

An increase in interest rates could result in a significant increase in the amount Bonterra pays to service debt, which could negatively impact the market price of the Common Shares.

Delay in Cash Payments

In addition to the usual delays in payment by the purchasers of oil and natural gas to the operators of Bonterra's properties, and by the operator to Bonterra, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blow-outs or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

Reserves Estimates

Although Sproule has prepared Bonterra's reserve figures using methods of estimating reserves consistent with those commonly followed in the industry and believe that those methods have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced. Probable reserves estimated for properties may require revisions based on the actual development strategies employed to prove such reserves. Estimated reserves may also be affected by changes in oil and natural gas prices. Declines in the reserves of Bonterra which are not offset by the acquisition or development of additional reserves may reduce the underlying value of the common shares to shareholders.

The reserve report under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Part II - 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.

Expiration of Licenses and Leases

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Hedging

From time to time, Bonterra may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, Bonterra may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. In addition, if the Company enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices.

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

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 repayment of indebtedness or payment of dividends to shareholders.

Abandonment and Reclamation Costs

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

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

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Political Uncertainty

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Company's existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that Bonterra relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Company's results.

Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for Bonterra's products. See *"Industry Conditions – Climate Change Regulation", "Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access" and "Industry Conditions – NAFTA/USMCA and other Trade Agreements"*.

Climate Change Regulations

The Company's exploration and production facilities and other operations and activities emit greenhouse gases ("GHG") which may require the Company to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. The federal carbon levy came into effect on April 1, 2019 and affects provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing.

The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with Bonterra’s operations, increasing costs and negatively impacting production. Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires, and most recently with extreme flooding in British Columbia, causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the ability to transport produced oil and natural gas as well as goods and services along supply chains. Certain of Bonterra’s properties are located in regions that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting operations.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Company's properties. An increase in royalties would reduce the Company’s earnings and cash flow and could make future capital investments or the Company’s operations uneconomic.

Reliance on Key Personnel

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

Human Resources

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

Management of Growth

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

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continues to implement its AB LMF, with changes to be gradually phased in throughout 2022, replacing the current AB LMR Program. The implementation of the AB LMF program or other changes to the requirements of liability management programs may result in significant increases to the Company's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the liability management regime may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Issuance of Debt

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

Information Technology Systems and Cyber-security

The Company has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

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

Social Media

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

Reputational Risk Associated with the Company's Operations

The Company's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Company's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Company has no control. In particular, the Company's reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property caused by the Company's operations, or due to opposition from special interest groups opposed to oil and natural gas development. In addition, if the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business.

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

Changing Investor Sentiment

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

Evolving Corporate Governance and Reporting Framework

The Company’s business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company’s securities. Bonterra is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company’s efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Dilution

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

Depletion of Reserves

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

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

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

Competition

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

Indigenous Claims

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

Breach of Confidentiality

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

Net Asset Value

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

Potential Conflicts of Interest

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

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

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

Management Estimates and Assumptions

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

Insurance Risks

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

Geo-Political Risks

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

Exposure to Widespread Pandemic

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19 or any other similar illnesses, could have an adverse impact on the Company's results, business, financial condition or liquidity.

On March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID-19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Company's results, business, financial condition or liquidity, for a substantial period of time.

The Company is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for the Company's key executives to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact the Company's results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

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

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

Access to Company Offices and Properties

The Company's ability to carry on its business is dependent upon the ability of its employees to physically access its offices and properties. If access to the Company's office or properties is interrupted, then the Company's ability to administer and manage its business may be materially and adversely affected.

Non-Governmental Organizations and Eco-Terrorism Risks

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

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

Global Financial Markets

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

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.

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.

Cost of New Technologies

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

Availability of Equipment and Qualified Personnel and Related Costs

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

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; availability and productivity of skilled labour; and regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Seasonality and Climate

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

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

Alternatives to, and Changing Demand for, Petroleum Products

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

Waterflood

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

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The products that Bonterra produces must be delivered through gathering, processing and pipeline systems, some of which are not owned by the Company, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from Bonterra's assets is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines.

Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect production and operations which may have a material adverse effect on the Company's business and financial condition.

A portion of Bonterra’s production is processed through facilities owned by third parties over which the Company has no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of third party facility operations could have a materially adverse effect on Bonterra’s production and ability to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Forward-Looking Information May Prove Inaccurate

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

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

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

The financial statements and the management's discussion and analysis of its financial condition and results of operations for the year ended December 31, 2022, as contained in the Company's Annual Report for the year ended December 31, 2022 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 15th day of each calendar month with the last day of each month being the corresponding payable date.

On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing on April 1, 2020. The following cash dividends were paid by Bonterra since 2020:

Month of Record and Payment Date	Amount per Share
January 2020	$0.01
February 2020	$0.01
March 2020	$0.01

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

CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of common shares without nominal or par value. Transactions during the years 2022 and 2021 in the shares of the common stock of the Company are as follows:

	December 31, 2022		December 31, 2021	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**35,000,952**	**772,781**	33,511,316	765,415
Shares issued for interest on subordinated promissory note	**-**	**-**	118,896	414
Issued pursuant to the Company's share option plan	**1,360,940**	**1,612**	183,740	378
Transfer from contributed surplus to share capital		**1,804**		168
Issued pursuant to the exercise of warrants	**551,000**	**4,270**	1,187,000	7,003
Transfer from warrants to share capital		**1,212**		(356)
Share issue costs, net of tax		**-**		(241)
Balance, end of year	**36,912,892**	**781,679**	35,000,952	772,781

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 3,691,289 (December 31, 2021 – 3,500,095 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, 2022 and December 31, 2021, and changes during the years ended on those dates is presented below:

	Number of options	Weighted average exercise price
At January 1, 2021	2,426,700	$2.63
Options granted	235,500	4.39
Options exercised	(266,600)	3.02
Options forfeited	(87,000)	1.96
Options expired	(47,000)	13.55
At December 31, 2021	2,261,600	$2.56
Options granted	2,051,500	8.10
Options exercised[1]	(1,544,850)	2.12
Options forfeited	(2,500)	3.14
Options expired	(14,000)	17.76
At December 31, 2022	2,751,750	$6.86

(1) 720,250 options were exercised under the cashless option method, which resulted in 536,340 shares being issued in which the Company received no proceeds. Under the cashless option method, the remaining options between the number of options exercised and shares issued are cancelled.

The following table summarizes information about options outstanding at December 31, 2022:

	Options Outstanding				Options Exercisable		
Range of exercise prices	Number outstanding	Weighted-average remaining contractual life		Weighted-average exercise price	Number exercisable		Weighted-average exercise price
$ 1.00 - $ 5.00	665,250	0.7 years	$	3.10	458,250	$	2.97
5.01 - 10.00	2,041,500	4.5 years		7.96	25,000		5.72
10.01 - 20.00	45,000	2.4 years		12.32	-		0.00
$ 1.00 - $ 20.00	2,261,600	1.1 years	$	2.56	1,430,750	$	2.16

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 2022	$5.77 - $8.06	2,870,400
February 2022	$7.50 - $9.86	2,349,400
March 2022	$8.70 - $13.16	4,410,200
April 2022	$3.21 - $4.54	627,000
May 2022	$10.29 - $12.46	2,682,000
June 2022	$8.16 - $13.75	5,405,700
July 2022	$7.19 - $9.83	4,465,100
August 2022	$8.00 - $9.64	3,243,500
September 2022	$6.19 - $8.74	2,511,700
October 2022	$7.05 - $9.08	2,667,800
November 2022	$7.17 - $10.35	5,624,500
December 2022	$5.98 - $8.02	4,206,100

On December 31, 2022, the closing price of Bonterra shares on the TSX was $6.76 (December 31, 2021 - $5.66).

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
John J. Campbell, ICD.D (2)(3)(4) Calgary, AB	Director May, 2020	An independent director and consultant that has over 25 years of experience in private equity, energy services, banking and trust company services. Mr. Campbell also serves as an Independent Director for Mynd Life Sciences Inc, Morcado Trust Company, and two capital pool companies, Haw Capital 2 Corp and Golo Mobile Inc. Mr. Campbell is also the former President and Co-Founder of Odyssey Trust Company.
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.
George F. Fink Calgary, AB	Director January, 1981	B.Com., C.A., Executive Chairman of the Board of Pine Cliff Energy Ltd.
Stacey E. McDonald, ICD.D(1)(2)(3)(4) Calgary, AB	Director August, 2021	Ms. McDonald is a director of Birchcliff Energy Ltd. and has over 15 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. Holder of the Institute of Corporate Directors' Director designation.

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.
Patrick G. Oliver Calgary, AB	President, Chief Executive Officer & Director September, 2022	B.Com., C.A., Mr. Oliver has over 35 years of E&P experience in various executive roles in both the public and private sector. Over the past 20 years, the majority as CEO, Mr Oliver was instrumental in the building and successful sale of four privately owned Birchill companies with operations in central Alberta. Mr Oliver is also a Director of Enercapita Energy Ltd., a private oil and gas company.
D. Michael G. Stewart(1)(2)(3)(4) Calgary, AB	Chair and Director March, 2021	B.Sc., P.Eng. (non-practicing), Corporate Director.
Robb D. Thompson Calgary, AB	Chief Financial Officer & Corporate Secretary February, 2011	B.Com., C.A., Mr. Thompson has been CFO and Corporate Secretary since February 2011.
Jacqueline R. Ricci(1)(3)(4) Toronto, ON	Director May, 2020	Vice President and Director at J. Zechner Associates since 1997. Ms. Ricci is also a director of Pine Cliff Energy Ltd.
Rodger A. Tourigny(1)(2)(4) Calgary, AB	Director May, 2013	B.Com., C.A., President of Tourigny Management Ltd. (Calgary), a private consulting company, since 1979.

Notes:
(1) Member of the Audit Committee. Chaired by Rodger A. Tourigny.
(2) Member of the Reserve Committee. Chaired by Stacey E. McDonald.
(3) Member of the Human Resources and Compensation Committee. Chaired by John J. Campbell
(4) Member of the Governance and Nominating Committee. Chaired by Jacqueline R. Ricci

Directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 5,272,545 common shares representing approximately 14.2 percent of the issued and outstanding common shares of Bonterra as at March 9, 2023 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

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.

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 Rodger A. Tourigny, D. Michael G. Stewart, Stacey E. McDonald and Jacqueline R. Ricci. 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**
Stacey McDonald	• Strategic and Financial Advisory services. Bachelor of Commerce Degree with ICD.D designation. • Ms. McDonald is an independent consultant and has over 15 years of experience in the energy and financial sectors From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. Institute of Corporate Directors' Director designation.

Jacqueline R. Ricci	• Vice President and Director at J. Zechner Associates since 1997. • CFA with many years of experience in evaluating business plans and management performance in small and mid capitalization companies in the Canadian market. • Direct experience in all aspects of reading and understanding financial statements.
D. Michael G. Stewart	• Corporate director with almost 50 years of experience in the Canadian energy industry and an extensive track record serving as a senior executive and on boards of directors and audit committees.
Rodger A. Tourigny (Chair)	• B. Com., C.A., private investor and financial consultant. • Over 30 years providing advice on major transactions, investments and ongoing financial matters in the oil and gas, real estate and financial services industries. • Many years of experience related to the supervision of the preparation of financial statements and as CFO of oil and gas entities.

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
2022	$166,000	$160,000	$ -	$ -
2021	$214,000	$132,000	$ -	$15,000

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, 2022, 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 13, 2022. 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, 2022 and 2021, which are included in Bonterra's Annual Report for the year ended December 31, 2022.

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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, 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, 2022**	**Canada**	**Nil**	**1,481,688**	**Nil**	**1,481,688**

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, 2022)"

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 7, 2023

(signed) Gary R. Finnis, P. Eng.
Senior Manager, Engineering

(signed) Jeffrey McKeeman, P. Eng.
Team Lead, Engineering

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, 2022, 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) "Patrick G. Oliver"
Patrick G. Oliver, Chief Executive Officer

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

(Signed) "Adrian Neumann"
Adrian Neumann, Chief Operating Officer

(Signed) "Brad A. Curtis"
Brad A. Curtis, Senior VP Business Development

(Signed) "Stacey E. McDonald"
Stacey E. McDonald, Director

(Signed) "Jacqueline R. Ricci"
Jacqueline R. Ricci, Director

(Signed) "John J. Campbell"
John J. Campbell, Director

(Signed) "D. Michael G Stewart"
D. Michael G. Stewart, Director

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

(Signed) "George F. Fink"
George F. Fink, Director

March 9, 2023

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) President, 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.