

BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2009

March 15, 2010

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GLOSSARY OF TERMS

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

"Amalco" means the entity resulting from the amalgamation of Bonterra, Novitas and Silverwing pursuant to the Bonterra Arrangement in 2008;

"Bonterra" means Bonterra Energy Corp. The Company formed on amalgamation of Bonterra Corp. and Bonterra Oil & Gas Ltd.;

"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 (consisting of all the issued and outstanding shares of Amalco (formed under the Bonterra Arrangement by the amalgamation of Bonterra Corp. and Novitas and following the completion of the Silverwing Arrangement, Silverwing merged with Amalco); unsecured notes issued by Amalco to the Trust and 95 percent royalties on the crude oil and natural gas property interests owned by Amalco).

"Bonterra Trust" means Bonterra Energy Income Trust;

"Comstate" means Comstate Resources Ltd., formerly a wholly owned subsidiary of Bonterra Corp.;

"Comstate Trust" means Comstate Resources 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;

"Novitas" means Novitas Energy Ltd., formerly a wholly owned subsidiary of Bonterra Corp.;

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

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

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

"Shareholder" means a holder of Bonterra common shares

"Silverwing" means Silverwing Energy Inc., formerly a wholly owned subsidiary of Bonterra Oil & Gas Ltd.;

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

"Sproule Report" means the independent engineering evaluations of Bonterra's oil, natural gas and NGLs interests prepared by Sproule dated February 4, 2009 and effective December 31, 2008 utilizing commodity price forecasts of Sproule dated December 31, 2008;

"Trust Indenture" means the Amended and Restated Trust Indenture dated June 28, 2004 between Comstate and the Trustee;

"Trustee" means Olympia Trust Company, or its successor as trustee of the Company;

"Trust Units" means the trust units of the former Bonterra Trust, each representing an equal undivided beneficial interest in the Trust; and

"Unitholder" means a holder of Trust Units.

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "\$" are to Canadian dollars.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbls – barrels
 Mbbls – thousand barrels
 Bbls/d – barrels per day
 NGLs – natural gas liquids
 Stb – standard barrel

Natural Gas

GJ – gigajoules
 GJ/d – gigajoules per day
 Mcf – thousand cubic feet
 MMcf – million cubic feet
 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 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.

BOE/d means BOE per day.

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

CONVERSIONS

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

<u>To convert from</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	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 the interest of providing the shareholders and potential investors in Bonterra Energy Corp. ("Bonterra" or the "Company") with information regarding the Company and its former subsidiaries, including Bonterra Trust and Bonterra Corp. and management's assessment of the Company's future plans and operations, this Annual Information Form contains or incorporates by reference forward-looking information that represents the Company's internal projections, expectations, estimates or beliefs concerning, among other things, future operating results and various components thereof or the Company's future economic performance. The projections, expectations, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties which may cause the Company's actual performance and financial results in future periods to differ materially from any projections, expectations, estimates and beliefs of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, such risk and uncertainties described in this Annual Information Form and in documents incorporated by reference into this Annual Information Form and the Company's other reports and filings with the Canadian securities authorities. Accordingly, Shareholders and potential investors are cautioned that events or circumstances could cause actual results to differ materially from those predicted.

STRUCTURE OF BONTERRA OIL & GAS LTD.

Bonterra Oil & Gas Ltd.

Bonterra Oil & Gas Ltd. was a high-yield, dividend paying, oil and gas company headquartered in Calgary, Alberta. The Company's assets consisted of all the issued and outstanding trust units of Bonterra Trust (consisting of all the issued and outstanding shares of Amalco (formed under the Bonterra Arrangement by the amalgamation of Bonterra Corp. and Novitas and following the completion of the Silverwing Arrangement, Silverwing merged with Amalco); unsecured notes issued by Amalco to the Trust and 95 percent royalties on the crude oil and natural gas property interests owned by Amalco).

Effective January 1, 2010, Bonterra Oil & Gas Ltd. wound up 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. (Bonterra) effective January 1, 2010.

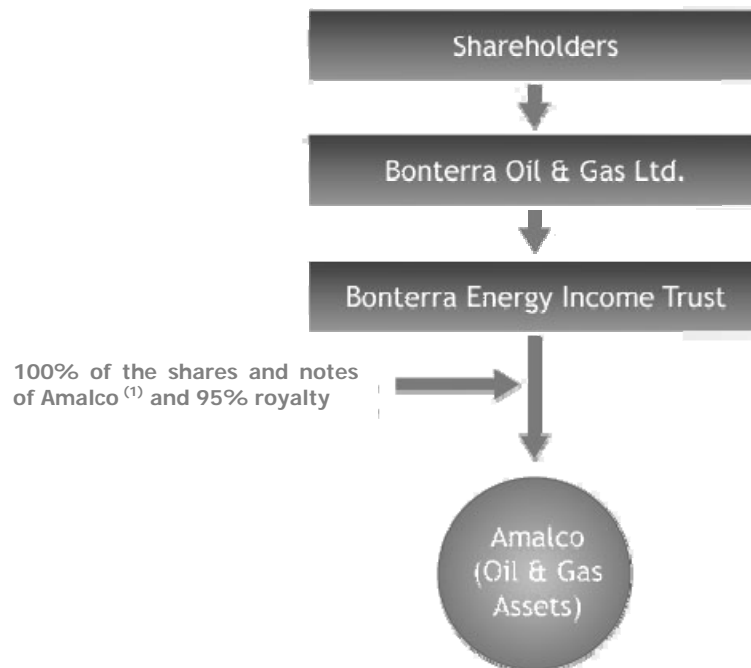
The head and principal office of Bonterra is located at:
901, 1015 4th Street S.W., Calgary, Alberta, T2R 1J4.

The Company's primary focus is to maintain and enhance cash dividends to its Shareholders through the optimum utilization and development of existing crude oil and natural gas properties and acquisition or development of new producing properties. Development efforts are concentrated in the Pembina field mainly in the Cardium, Edmonton and Belly River zones.

Transfer Agent and Registrar

The Registrar and Transfer Agent for the common shares is Olympia Trust Company at 2300, 125 – 9th Avenue S.E., Calgary, Alberta, T2G 0P6 and Olympia Transfer Services Inc., Suite 920, 120 Adelaide Street West, Toronto, Ontario, M5H 1T1.

In 2009, the structure of Bonterra Oil & Gas Ltd. and the flows of cash from Amalco to the Company are set forth below:



⁽¹⁾ Amalco was formed under the Bonterra Arrangement by the amalgamation of Bonterra Corp. and Novitas and following the completion of the Silverwing Arrangement in November 2008, Silverwing merged with Amalco.

Bonterra Oil & Gas Ltd. 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." (Bonterra) effective January 1, 2010.

Prior to the amalgamation, Bonterra Energy Income 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.

The common shares continue to trade under the symbol "BNE".

GENERAL DEVELOPMENT OF THE BUSINESS

Historical Overview

Bonterra Oil & Gas Ltd. was formed on November 12, 2008 under an arrangement under the Business Corporations Act (Alberta) (the "ABCA") involving Silverwing Energy Inc. (Silverwing), Bonterra Trust, Bonterra Corp. and the holders of securities of Silverwing (the "Silverwing Arrangement") and the arrangement under the ABCA involving Bonterra Trust, Bonterra Corp, Novitas Energy Ltd. (Novitas), SRX Post Holdings Inc. ("SRX", renamed Bonterra Oil & Gas Ltd.) and the holders of securities of Bonterra Trust.

Summary of the Silverwing Arrangement

Under the terms of the Silverwing Arrangement, holders of common shares of Silverwing (Silverwing Shares) received either: (i) \$0.073 in cash; or (ii) 0.002166 of a unit of Bonterra Trust (Trust Unit) for each Silverwing Share held by such holder.

As a result of the Silverwing Arrangement, Silverwing became a wholly-owned subsidiary of Bonterra Trust. An aggregate of 7,745 Trust Units were issued to holders of Silverwing Shares who elected to receive Trust Units. Holders of Silverwing Shares that elected or were deemed to have elected to receive cash under the Silverwing Arrangement received an aggregate of \$13,481,986.08 in cash. Each of the former officers and directors of Silverwing have resigned.

Summary of the Bonterra Arrangement

Under the terms of the Bonterra Arrangement, Bonterra Oil & Gas Ltd. acquired all of the outstanding Trust Units by issuing common shares to holders of Trust Units on a one-for one basis. In addition, Bonterra Corp. and Novitas, which held the operating assets of Bonterra Trust, amalgamated to form a new operating subsidiary of Bonterra Trust (Amalco).

Prior to implementing the Bonterra Arrangement, SRX underwent a reorganization in connection with a Plan of Compromise and Arrangement (CCAA Plan) under the Companies' Creditors Arrangement Act (Canada) and the Canada Business Corporations Act which resulted in: (i) Bonterra Corp. advancing a loan of approximately \$11,250,000 to SRX; (ii) all liabilities of SRX other than the Bonterra loan, being extinguished or settled; (iii) the share capital of SRX being reorganized to provide for the redemption of all of its outstanding common shares for no consideration; (iv) all of SRX's cash, including the funds advanced by Bonterra Corp, being paid and distributed to SRX creditors in accordance with their rank within the CCAA Plan; (v) the province of the registered office of SRX being changed to Alberta; and (vi) the corporate name of SRX being changed to Bonterra Oil & Gas Ltd.

As a result of the Bonterra Arrangement, Bonterra Trust became a wholly-owned subsidiary of Bonterra Oil & Gas Ltd. An aggregate of 17,257,603 Bonterra common shares were issued to holders of Trust Units.

Each of the former officers and directors of SRX had resigned and were replaced by nominees of Bonterra Corp. Bonterra common shares commenced trading on the TSX under the symbol "BNE".

Upon completion of both the Silverwing Arrangement and the Bonterra Arrangement, Silverwing and Bonterra Corp. were amalgamated under the name Bonterra Energy Corp.

A detailed description of both the Silverwing Arrangement and the Bonterra Arrangement is contained in the joint management information circular of Bonterra Trust and Silverwing, a copy of which is available on SEDAR at www.sedar.com.

Bonterra Trust

The Trust was formed on May 15, 2001 as Comstate Resources Income Trust. On January 31, 2002 the Trust merged with the former Bonterra Energy Income Trust and continued on as Bonterra Energy Income Trust under the Trust Indenture.

Establishment of Comstate Resources Income Trust

The Trust commenced operations through an arrangement that resulted in the conversion of the share holdings in Comstate Resources Ltd. into investments in the units of Comstate Trust. The arrangement resulted in the Comstate shareholders receiving units of Comstate Trust in exchange for their common shares of Comstate. The arrangement also resulted in the distribution to shareholders of Comstate of approximately 13,647,000 shares of Comaplex Minerals Corp. (a former subsidiary of Comstate) and approximately \$4,549,000 in cash. After the conversion, Comstate Trust had issued 5,675,757 units.

The arrangement was undertaken to obtain a number of benefits to Comstate's shareholders including:

1. The separation of Comstate's oil and gas assets from its mineral investments. The Comstate Board concluded that a separation of these assets would result in better returns for its shareholders and provide more opportunities for each of the two divisions. Excessive taxation on a corporate level basis had previously always prevented this change.
2. Comstate had a history of making distributions to shareholders. From its 1998 cash flow it paid dividends of \$0.14 per share; from 1999 cash flow it paid dividends of \$0.19 per share; and from 2000 cash flow it paid dividends of \$0.31 per share. By converting to an income trust, Comstate was able to distribute cash flow on a more tax effective basis from a trust and corporate basis and move much of the taxation directly to the Comstate Trust unitholders.
3. Comstate Trust was expected to grow in size through acquisitions of producing oil and gas properties, acquisitions of companies, mergers with trusts or companies, and by drilling mainly low-risk development prospects. Comstate Trust had lower management and administration costs than most other trusts, which made it relatively more attractive for other companies or trusts to become associated with Comstate Trust.
4. It was anticipated that the reorganized structure of Comstate would allow greater access to equity to fund Comstate Trust's growth.
5. The reorganized structure of Comstate as a trust would attract new investors and provide a more active and liquid market for the units than existed for the common shares.

Merger with Old Bonterra Energy Income Trust

On January 31, 2002, Comstate Trust merged with old Bonterra Energy Income Trust. Subsequent to the merger Comstate Trust changed its name to Bonterra Energy Income Trust. The merger resulted in the former Unitholders of old Bonterra Energy Income Trust owning more Trust Units in the combined trust than the former Comstate Trust unitholders. The merger was accounted for as a reverse take-over whereby old Bonterra Energy Income Trust was deemed to be the acquiring trust. The result of this treatment was to record the assets and liabilities of Comstate Trust at their fair market values while leaving old Bonterra

Energy Income Trust assets and liabilities at their carrying value. The merger resulted in Bonterra having total outstanding Trust Units of 13,368,405.

Equity Issuances

On May 27, 2009, Bonterra closed a private placement which consisted of the issuance of 1,068,000 common shares at a price of \$16.85 per share for gross proceeds of \$17,995,800.00.

Property and Corporate Acquisitions and Dispositions in 2009, 2008 and 2007

On July 2, 2009, Bonterra completed its acquisition of Cobalt Energy Ltd. The Company issued 201,438 common shares and assumed \$2,856,000 of negative working capital and incurred approximately \$170,000 in acquisition costs for a total calculated accounting cost of \$7,105,000. This acquisition resulted in acquiring an additional 40 BOE per day of production as well as increasing the Company's working interest in approximately 11 gross sections of land with potential Cardium horizontal locations in the Pembina area of Alberta.

On November 6, 2009, the Company closed a purchase and sale agreement to divest of a portion of its Shaunavon oil production to Eagle Rock Exploration Ltd (Eagle Rock). The proceeds of disposition included cash of \$23,729,000 and 30,769,200 common shares. These funds were used to retire debt and therefore provide additional room in Bonterra's line of credit for additional 2010 drilling. In addition, the common shares received for the Shaunavon properties will provide further funds upon their ultimate sale. Eagle Rock has since changed its name to Wild Stream Exploration Inc. (Wild Stream) (TSXV: WSX) and consolidated its common shares on a 30:1 basis resulting in Bonterra holding 1,025,640 common shares of Wild Stream at December 31, 2009 with a quoted market value of \$4,462,000.

Subsequent to December 31, 2009, the Company entered into a purchase and sale agreement to divest its Southeast Saskatchewan Pinto property. Production from this property was approximately 60 BOE per day consisting primarily of light sweet crude oil. The proceeds of disposition consist of approximately \$5,600,000 cash. The disposition closed February 23, 2010 and was effective February 1, 2010.

On November 12, 2008, Bonterra acquired Silverwing that had production of approximately 650 BOE per day consisting entirely of natural gas and natural gas liquids in the province of British Columbia, 10,000 acres and a right to earn an additional 38,000 acres of non-producing lands in Alberta and British Columbia and approximately \$77 million in tax pools at a cost of approximately \$14,016,000.

On October 30, 2007 (with an effective date of May 1, 2007), Bonterra swapped its interest in the Dodsland Area (Saskatchewan) for additional producing properties in the Pembina Area (Alberta).

Canadian Federal Government's Taxation of Income Trusts

On November 12, 2008, Bonterra Energy Income Trust converted to a corporation and thus is no longer subject to the Canadian federal government's taxation of income trusts legislation. (See Section "Tax Horizon" in the Annual Information Form for a full discussion of the Company's tax pools and expected tax horizon).

Legal Proceedings

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

OPERATIONAL INFORMATION - NI51-101

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”) with an effective date of December 31, 2009 contained in the Sproule Report dated February 4, 2010.

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 National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("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 Proved plus Probable Reserves and no attempt was made to evaluate possible reserves.

It should not be assumed 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".

FORM 51-101F1 PART 2.1(1) SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2009 FORECAST PRICES AND COSTS

Reserve Category:	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
PROVED						
Developed Producing	14,247.8	12,638.4	32,103	28,749	1,270.8	886.6
Developed Non-Producing	220.0	177.2	761	617	7.3	5.3
Undeveloped	3,283.9	2,560.1	3,779	3,281	190.2	134.9
TOTAL PROVED	17,751.8	15,375.7	36,643	32,647	1,468.3	1,026.7
PROBABLE	7,922.7	6,399.5	12,896	11,412	424.9	294.3
TOTAL PROVED PLUS PROBABLE	25,674.5	21,775.2	49,539	44,059	1,893.2	1,321.1

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, 2009
FORECAST PRICES AND COSTS

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

(\$ Millions)						Future Net Value
Reserve Category:	0%	5%	10%	15%	20%	10%/yr (\$/BOE)
PROVED						
Developed Producing	1,045.3	580.8	407.7	319.1	264.8	22.26
Developed Non-Producing	15.8	13.0	11.2	9.9	9.0	39.31
Undeveloped	135.5	102.4	79.2	62.3	49.7	24.44
TOTAL PROVED	1,196.6	696.2	498.1	391.4	323.5	22.80
PROBABLE	702.9	260.6	135.6	84.7	58.4	15.78
TOTAL PROVED PLUS PROBABLE	1,899.5	956.9	633.7	476.1	381.8	20.82

The Company only operates in Canada.

* Disclosure provided herein in respect of barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6 MCF:1 Bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

FORM 51-101F1 PART 2.1(2)
SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
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	903.8	533.5	387.5	309.1	259.4
Developed Non-Producing	11.8	10.6	9.7	8.9	8.3
Undeveloped	101.4	79.4	63.3	51.1	41.6
TOTAL PROVED	1,017.0	623.4	460.4	369.1	309.3
PROBABLE	527.4	195.8	102.5	64.5	44.9
TOTAL PROVED PLUS PROBABLE	1,544.5	819.2	562.9	433.7	354.2

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(b)
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

(\$ Millions)								
Reserves Category:	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment/ Other Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	2,471.8	335.1	813.3	90.1	36.6	1,196.6	179.6	1,017.0
Proved Plus Probable	3,749.7	562.3	1,132.8	112.1	42.9	1,899.5	355.1	1,544.5

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(c)
NET PRESENT VALUE OF FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

Reserves Category:	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (\$Millions)	Unit Value Before Income Taxes (Discounted at 10%/Year) (\$/BOE)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	456.8	23.19
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)*	41.3	19.22
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	582.9	21.26
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)*	50.8	16.79

* Includes corporate Capital GCA, if applicable.

Unit values are based on net reserves.

The Company only operates in Canada.

PART III – PRICING ASSUMPTIONS

Forecast Prices

The Forecast Prices used in the appendix are:

Year	Edmonton Par Price (Cdn \$ per Bbl)	Natural Gas AECO-C Spot (Cdn \$ per MMBtu)	Butanes Edmonton (Cdn \$ per Bbl)	Pentanes Edmonton (Cdn \$ per Bbl)	Inflation Rate (%/Yr)	Exchange Rate (\$US/\$Cdn)
HISTORICAL						
2004	52.91	6.87	41.37	53.91	1.4	0.770
2005	69.29	8.58	45.20	69.13	1.3	0.826
2006	73.30	7.16	59.32	75.03	1.5	0.882
2007	77.06	6.65	63.71	77.33	2.0	0.935
2008	102.85	8.15	75.09	104.70	1.0	0.943
2009	66.20	4.19	47.07	68.13	2.0	0.880
FORECAST						
2010	84.25	5.36	59.65	86.28	2.0	0.920
2011	89.99	6.21	63.72	92.16	2.0	0.920
2012	92.61	6.44	65.57	94.84	2.0	0.920
2013	96.19	7.23	68.11	98.51	2.0	0.920
2014	98.13	7.98	69.48	100.50	2.0	0.920

Crude oil, natural gas and liquid prices escalate at 2 percent thereafter.

The above prices were provided by the independent reserves evaluator Sproule Associates Limited

The Company's weighted average historical prices by production type for the 2009 financial year are as follows:

- Light and Medium Crude Oil per barrel \$62.31
- Natural Gas per Mcf \$ 4.15
- Natural Gas Liquids per barrel \$47.05

PART IV – RECONCILIATION OF CHANGES IN RESERVES
RECONCILIATION OF TRUST GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

	Light and Medium Oil and Natural Gas Liquids			Natural Gas			BOE		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mmcf)		(Mmcf)	(Mboe)		(Mboe)
December 31, 2008	17,991	4,876	22,867	36,571	13,675	50,246	24,086	7,155	31,241
Extension	1,983	4,079	6,062	1,024	1,516	2,540	2,154	4,332	6,485
Improved recovery	0	0	0	0	0	0	0	0	0
Technical revisions	2,138	(559)	1,579	3,350	(2,317)	1,034	2,696	(945)	1,751
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	142	111	253	53	43	96	151	118	269
Dispositions	(1,010)	(141)	(1,151)	(7)	(2)	(9)	(1,011)	(141)	(1,152)
Economic factors	(877)	(18)	(895)	(290)	(19)	(309)	(925)	(21)	(947)
Production	(1,146)	0	(1,146)	(4,059)	0	(4,059)	(1,823)	0	(1,823)
December 31, 2009	19,220	8,348	27,568	36,642	12,896	49,539	25,327	10,498	35,824

The Company only operates in Canada.

PART V – ADDITIONAL INFORMATION RELATED TO RESERVE DATA

Undeveloped Reserves

Proved Light and Medium Oil Gross reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	2,553	2,553	Opening balance (cumulative and first attributed are equal).
2007	652	2,808	Of the opening balance PUDS, 61 were removed due to adjustments, 689 PUDs related to wells that were drilled and were converted to proved developed producing and the Trust received an increase in PUDs of 353 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs related to the extension of the Trust's drilling program to 2010 from 2009.
2008	0	2,258	Of the 2007 PUDs, 550 PUDs related to wells that were drilled and were converted to proved developed producing.
2009	1,978	3,284	Of the 2008 PUDs, 952 PUDs related to wells that were drilled and were converted to proved developed producing. The Company received an increase in PBUDs of 1,978 related to the Cardium horizontal drilling program initiated by the company in 2009.

Probable Light and Medium Oil Gross Reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	891	891	Opening balance (cumulative and first attributed are equal).
2007	180	855	Of the opening balance PBUDs, 39 wells were removed due to adjustments, 193 PBUDs related to wells that were drilled and were converted to probable/proved developing producing and the Trust received an increase in PBUDs of 16 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs related to the extension of the Trust's drilling program to 2010 from 2009.
2008	42	605	Of the 2007 PBUDs, 292 PBUDs related to wells that were drilled and were converted to probable/proved developed producing. The Company received an increase in PBUDs of 42 related to the extension of the Company's drilling program in 2009.
2009	4079	4147	Of the 2008 PBUDs, 537 PBUDs related to wells that were drilled and were converted to probable developed producing. The Company received an increase in PBUDs of 4,079 related to the Cardium horizontal drilling program initiated by the company in 2009.

Proved Associated and Non Associated Natural Gas Gross Reserves (Mmcf)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	2,592	2,592	Opening balance (cumulative and first attributed are equal).
2007	678	3,355	Of the opening balance PUDs, 74 were removed due to adjustments, 773 PUDs related to wells that were drilled and were converted to provide developed producing and the Trust received an increase in PUDs of 932 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs relate to the extension of the Trust's drilling program to 2010 from 2009.
2008	763	3,594	Of the 2007 PUDs, 524 PUDs related to wells that were drilled and were converted to proved developed producing and the Company received an increase in PUDs of 763 of which 579 are attributed to the Silverwing acquisition.
2009	912	3,779	Of the 2008 PUDs, 727 PUDs related to wells that were drilled and were converted to proved developed producing. 160 PUDs were added for two new Edmonton gas prospects. The Company also received an increase in PUDs of 752 related to the Cardium horizontal drilling program initiated by the company in 2009.

Probable Associated and Non Associated Natural Gas Gross Reserves (Mmcf)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	991	991	Opening balance (cumulative and first attributed are equal).
2007	192	1,031	Of the opening balance PBUDs, 20 were removed due to adjustments, 326 PBUDs related to wells that were drilled and were converted to probable/proved developed producing and the Trust received an increase in PBUDs of 194 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs related to the extension of the Trust's drilling program to 2010 from 2009.
2008	1,622	2,574	Of the 2007 PBUDs, 79 PBUDs related to wells that were drilled and were converted to probable/proven developed producing and the Company received an increase in PBUDs of 1,622 of which 1,576 are attributed to the Silverwing acquisition.
2009	1,691	3,885	Of the 2008 PBUDs, 380 PBUDs related to wells that were drilled and were converted to probable developed producing. 221 PBUDs were added for two new Edmonton gas prospects. The Company also received an increase in PBUDs of 1,471 related to the Cardium horizontal drilling program initiated by the company in 2009.

Proved Coal Bed Methane Gross Reserves (Mmcf)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	-	-	Opening balance (cumulative and first attributed are equal).
2007	-	-	No PUD adjustments.
2008	-	-	No PUD adjustments.
2009	-	-	No PUD adjustments.

Probable Coal Bed Methane Gross reserves (Mmcf)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	-	-	Opening balance (cumulative and first attributed are equal).
2007	-	-	No PBUD adjustments.
2008	-	-	No PBUD adjustments.
2009	-	-	No PBUD adjustments.

Proved Natural Gas Liquids Gross Reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	77	77	Opening balance (cumulative and first attributed are equal).
2007	38	186	Of the opening balance PUDs, 2 were removed due to adjustments, 23 PUDs related to wells that were drilled and were converted to proved developed producing and the Trust received an increase in PUDs of 96 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs relate to the extension of the Trust's drilling program to 2010 from 2009.
2008	-	112	Of the 2007 PUDs, 74 PUDs related to wells that were drilled and were converted to proved developed producing.
2009	40	190	Of the 2008 PUDs, the Company received an increase in PUDs of 40 related to the Cardium horizontal drilling program initiated by the company in 2009. Overall, the liquid component of the Cardium solution gas was increased to reflect actual field performance. An increase of 39 PUDs resulted.

Probable Natural Gas Liquids Gross Reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2007	30	30	Opening balance (cumulative and first attributed are equal).
2007	39	54	Of the opening balance PBUDs, 1 was removed due to adjustments, 34 PBUDs related to wells that were drilled and were converted to probable/proven developed producing and the Trust received an increase in PBUDs of 20 related to undrilled wells carried over from the 2006 engineering report. Additional current year PUDs relate to the extension of the Trust's drilling program to 2010 from 2009.
2008	2	39	Of the 2007 PBUDs, 17 PBUDs related to wells that were drilled and were converted to probable/proven developed producing. Additional current year PUDs relate to the extension of the Company's drilling program to 2010 from 2009.
2009	81	120	The Company received an increase in PUDs of 81 related to the Cardium horizontal drilling program initiated by the company in 2009.

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 2009 Annual Report.

Future Development Costs

\$ Millions	Forecast Prices and Costs	
	Proved	Proved Plus Probable
Year		
2010	30.7	39.2
2011	31.6	36.9
2012	27.8	36.0
2013	0	0
2014	0	0
Total		
Undiscounted	90.1	112.1

The above future development costs will be funded primarily from 2010 to 2013 cash flow from operations, sale of investments, exercising of employee share options and if required from the Company's line of credit. Should these sources of funds be insufficient the Company will access the public markets as required.

PART VI – OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

All of Bonterra's oil and natural gas properties are located in the Provinces of Alberta, Saskatchewan and British Columbia. In 2009, production volumes from Bonterra's properties were approximately 63 percent crude oil and NGLs and 37 percent natural gas on a BOE basis. During the year ended December 31, 2009, Bonterra's oil and natural gas properties yielded average production of 4,994 BOE per day (2008 - 4,346 BOE per day, 2007 – 4,218 BOE per day). As at December 31, 2009 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 35,824 MBOE.

Pembina Area, West Central Alberta

Properties

Pembina is Bonterra's main property. It is the Company's largest producing asset and represents 89.2 percent of Proved plus Probable reserves. Production in Pembina is primarily oil and solution gas from the Cardium formation and to a lesser extent natural gas from the Edmonton Sands with the remainder coming from the Belly River, Paskapoo and the Ardley Coals.

The Pembina Cardium field is the largest conventional oil field in Canada with estimated original oil in place of 7.8 billion barrels with an average recovery to date of just 17 percent. This mature field has proved to be a significant area for multi-zone oil and natural gas exploration with predictable results. Bonterra is the third largest Cardium operator in the area after acquiring the properties throughout the last 15 years. After a period of low commodity prices and beginning in 2000, Bonterra pursued a targeted infill drilling program, low-cost optimization, recompletions and key acquisitions which have resulted in increased reserves and maximized income from the properties and a reduction in the decline rate. This clearly illustrates Bonterra's ability to provide sustainability and performance for shareholders.

In 2009, Bonterra executed a targeted horizontal, multi-stage frac drilling program, predominantly on lands located on the perimeter of the main pool, commonly termed the "Halo" area. The program has provided the Company with significant potential upside in the Halo area and in the main Pembina Cardium field which could potentially substantially increase both the original-oil-in-place and the ultimate recovery. Bonterra drilled seven Pembina Cardium horizontal wells (5.41 net) during 2009, all within the Halo area and has produced approximately 111,266 barrels of oil from these wells since the first one came on production in February 2009. Bonterra's working interest in the wells drilled in 2009 is approximately 73 percent.

In addition, the implementation of two CO₂ pilot projects in the Cardium zone by other industry operators in the area points to the vast upside of these enhanced oil recovery projects in the Pembina field. Environmental concerns over CO₂ emissions, location of a low cost source of CO₂, development of infrastructure and supportive environmental regulations would be required to improve feasibility. Bonterra intends to continue to investigate its potential as a long-term business strategy.

A significant portion of Bonterra's Pembina production in natural gas is derived primarily from the shallow Edmonton sands that consist of a large number of varied quality reservoir sands. These numerous channel sands are distributed throughout the Company's lands and multiple sands can be completed in a single well bore. These wells are drilled to depths shallower than 750 meters and make use of existing infrastructure that reduces development and operating costs. Bonterra is evaluating the use of horizontal, multi-stage frac technology in the thicker and tighter sands. Further development in the Edmonton will occur when infrastructure issues are resolved and natural gas prices improve. Wells from the Edmonton sands generally have lower productivity and benefit from the new royalty framework in Alberta.

Facilities

Bonterra has ownership in all significant facilities required to process its Pembina production including gathering systems, satellites, batteries, water disposal plants, pipelines, compressor stations and gas plants. All operated Pembina oil production is processed through one of its approximately forty owned and operated facilities for emulsion treating and water disposal. All non-operated oil production is processed through non-operated facilities in which Bonterra has ownership. Natural gas and solution gas are processed to separate liquids and remove water in one of six non-operated gas plants that Bonterra has ownership in.

Shaunavon Area, Southwest Saskatchewan

Properties

Bonterra's Shaunavon properties are located in the Chamberly field and produce medium density crude oil from the upper Shaunavon formation. The property is being produced under waterflood. The wells in this area are generally long-life with stable, low-decline production profiles and Bonterra will be optimizing the waterflood to further increase profitability from the existing property.

In 2009, Bonterra divested of a portion of its Shaunavon oil production consisting of approximately 210 barrels per day of medium gravity oil production and 18.5 sections of land primarily in the Whitemud area of Southwestern Saskatchewan. The proceeds of disposition included cash of \$23,729,000 and 30,769,200 common shares in the acquiring company (approximately 4.2 percent of the company at the time of the transaction). Proceeds from the sale were used to accelerate Bonterra's horizontal Pembina Cardium development program. Bonterra's current production from its remaining properties is approximately 120 BOE per day.

Facilities

Bonterra has ownership in all facilities required to process its Shaunavon production. All oil production is processed through an 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 solution gas.

Prespatou Area, Northeast British Columbia

The corporate acquisition of Silverwing in late 2008 created a new core area in the Prespatou area of northeast British Columbia (NEBC) with significant potential for further development. The properties consist almost entirely of natural gas and associated natural gas liquids with production of approximately 535 BOE per day.

Upon acquisition of this property, the Company focused on integrating the properties into its asset base and was able to increase production in the area by participating in the drilling of two gross (0.4 net) gas wells in early 2009.

Bonterra focused its 2009 capital development program on its Pembina Cardium properties to take advantage of the higher crude oil pricing environment compared to natural gas pricing and to take advantage of the Alberta government's short term royalty incentive plan. The Company is re-evaluating the geology of the entire area to access potential opportunities and identify new ones. The 2010 development plans will focus on optimization of production from existing well bores with its magnitude depending upon commodity prices.

Facilities

The NEBC area facilities are comprised of five gathering systems that each feed into an independent compressor station. Bonterra has operated and non-operated ownership in these facilities with working interests varying from five to 100 percent. There was significant amounts of excess facility capacity throughout the area that will allow for increases in production and Bonterra completed a facility optimization project that matched facility capacity with current and future field production rates so that cashflow from the property was maximized. After the gas is gathered and compressed through the company owned gathering systems and compression facilities, it is delivered to the Spectra Energy gas transmission pipeline for transportation to the McMahon gas plant located 10 kilometres east of Fort St. John for treating and processing.

Well Count

The wells in which Bonterra had an interest as at December 31, 2009 and which 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	680.0	398.1	140.0	71.0	51.0	21.6	11.0	9.4	731.0	419.7	151.0	80.4
BC	-	-	78.0	35.3	-	-	25.0	20.2	-	-	103.0	55.4
SK	28.0	26.5	3.0	3.0	5.0	3.9	1.0	1.0	33.0	30.3	4.0	4.0
Total	708.0	424.6	221.0	109.3	56.0	25.4	25.4	30.6	764.0	450.0	258.0	139.9

Properties with No Attributable Reserves

The Company's property with no attributable reserves consists of approximately 35,564 gross and 23,423 net acres in NEBC, the Shaunavon area of Saskatchewan and the Pembina and Lamont areas of Alberta. None of these land rights require any work commitment and 19,305 gross (13,044 net) acres are subject to expiry in the next twelve months. The Company is currently reviewing these properties with a focus on maximizing their value.

Risk Management Commodity Contracts

The Company has used various risk management contracts in the past to set price parameters for a portion of its production. Management, in agreement with the Board of Directors, decided that at least in the near term it will discontinue the use of commodity price agreements. The Company will assume full risk in respect of commodity prices.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs are based on management's estimation of abandonment requirements using current costs escalated at an inflation rate of two percent per annum. Cost estimations adhere in all material respects to the "best practices" recommended in the COGE handbook which are in accordance with principles and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers.

The Company expects to incur abandonment costs in respect to 1,022 gross wells (589.9 net). The total amount of costs expected to be incurred is \$64,482,000 (2008 - \$58,903,000) prior to discounting and \$8,904,000 (2008 - \$9,680,000) discounted at 10 percent. This includes \$31,661,000 (\$5,253,000 discounted at 10 percent) for injectors and suspended wells that were not included in the calculation of the attached future net revenue.

The following table provides the anticipated amount of abandonment and reclamation costs that the Company expects to pay in the next three financial years:

Year (\$ 000s)	Total Abandonment and Reclamation Costs Including Well Abandonment and Disconnection Costs All Net of Salvage Value
2010	875
2011	1,048
2012	996

Of the above amounts \$23,000, \$179,000 and \$109,000 of the 2010, 2011 and 2012 amounts, respectively, have been deducted in estimating future net revenue.

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	20-100	21,671
Eligible capital expenditures	7	7,363
Share issue costs	20	2,973
Canadian oil and gas property expenditures	10	26,282
Canadian development expenditures	30	59,141
Canadian exploration expenditures	100	11,174
SR&ED expenditures	100	80,357
Income tax losses carried forward ⁽¹⁾	100	223,629
		<u>432,590</u>

⁽¹⁾ Federal income tax losses carried forward expire in the following years; 2013 - \$1,069,000, 2024 - \$3,347,000, 2025 - \$7,532,000, 2026 - \$46,670,000, 2027 - \$117,189,000, 2028 - \$34,726,000, 2029 - \$13,096,000.

The Company has \$27,670,000 (2008 - \$27,670,000) remaining of investment tax credits that expire in the following years; 2019 - \$3,469,000, 2020 - \$3,059,000, 2021 - \$4,667,000, 2022 - \$3,909,000, 2023 - \$3,155,000, 2024 - \$1,995,000, 2025 - \$2,257,000, 2026 - \$2,405,000, 2027 - \$2,009,000, 2028 - \$745,000.

The Company also has \$143,061,000 of capital loss carry forwards which can only be claimed against 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)	2009	2008
Land	5,184	376
Acquisitions	7,105	15,347
Disposals	(30,191)	-
Exploration and development costs	22,912	29,684
Net petroleum and natural gas capital expenditures	<u>5,640</u>	<u>45,407</u>

Exploration and Development Activities

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

	2009					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	15.0	12.4	-	-	15.0	12.4
Natural gas	2.0	0.4	-	-	2.0	0.4
Dry	-	-	-	-	-	-
Total	17.0	12.8	-	-	17.0	12.8
Success rate	100%	100%	-	-	100%	100%

2008							
	Development		Exploratory		Total		
	Gross	Net	Gross	Net	Gross	Net	
Crude oil	35.0	25.5	1	0.3	36.0	25.8	
Natural gas	8.0	5.1	-	-	8.0	5.1	
Dry	-	-	-	-	-	-	
Total	43.0	30.6	1	0.3	44.0	30.9	
Success rate	100%	100%	100%	100%	100%	100%	

2007							
	Development		Exploratory		Total		
	Gross	Net	Gross	Net	Gross	Net	
Crude oil	22.0	15.3	-	-	22.0	15.3	
Natural gas	2.0	0.7	-	-	2.0	0.7	
Dry	-	-	-	-	-	-	
Total	24.0	16.0	-	-	24.0	16.0	
Success rate	100%	100%			100%	100%	

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

Production Estimates

2010			
	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)
Pembina Area, Alberta	3,314	6,455	243
Prespatou Area, Northeast BC	-	3,479	23
Shaunavon Area, Saskatchewan	120	-	-
Other	158	699	17
	3,592	10,633	283

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 2009

Product Type Yearly Quarter	Production Volume per day	Average per Unit of Volume (\$/bbl and \$/Mcf)			
		Price	Royalties	Costs	Netbacks
Light and Medium Oil (Bbls)					
1 Quarter	2,997	47.21	3.40	21.00	22.81
2 Quarter	2,810	62.20	3.99	21.67	36.54
3 Quarter	2,840	68.84	5.83	19.42	43.59
4 Quarter	2,881	71.22	11.04	19.40	40.78
Natural Gas (Mcf)					
1 Quarter	11,877	5.19	0.42	1.04	3.73
2 Quarter	11,551	3.64	0.14	1.44	2.06
3 Quarter	10,881	3.13	0.18	1.21	1.74
4 Quarter	10,193	4.76	0.29	1.41	3.06
Natural Gas Liquids (Bbls)					
1 Quarter	271	30.29	7.53	10.72	12.04
2 Quarter	219	28.72	7.16	15.08	6.48
3 Quarter	244	32.94	10.94	13.37	8.63
4 Quarter	301	37.53	11.25	14.69	11.59

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

	2009		
	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)	Total (BOE per day)
Pembina, AB	2,595	6,419	3,665
Shaunavon, SK	318	-	318
Prespatou Area, BC	27	3,706	645
Other	201	995	366
	3,141	11,120	4,994

Lease Holdings

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

	2009		2008	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	168,749	106,785	152,917	92,438
Saskatchewan	14,483	12,793	31,182	28,000
British Columbia	73,910	30,373	73,910	30,373
	257,142	149,951	258,009	150,811

Historical Production Revenues

Gross production revenues (before deduction of royalties payable to others) for Bonterra's oil and natural gas production during the periods ended December 31, 2009 and 2008 are as follows:

	2009		2008	
	\$ 000s	% of Total Revenue	\$ 000s	% of Total Revenue
Crude Oil and NGLs	68,850	80	98,725	81
Natural Gas	16,862	20	23,005	19
	85,712	100	121,730	100

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 dividends to shareholders, while at the same time striving for long-term growth in the value of the assets of Bonterra. These two objectives are fundamental to the operation of Bonterra and are balanced to maximize long-term benefits to shareholders.

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

Dividends

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

shareholders on the corresponding dividend payment date, generally on the last day of each calendar month.

See "Dividends/Distributions to Unitholders" for the past cash dividends/distributions made or declared to shareholders (previously unitholders) of Bonterra.

Environmental Obligations

Bonterra emphasizes the importance of creating and maintaining a safe and environmentally sound operation by focusing on having upper 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 thorough 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. The review of such incidents allows Bonterra, including upper 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, property damage or loss and business interruption.

Borrowing

The Company's debt obligations consist of a bank facility and borrowing from related parties. Details of these banking arrangements are contained in Notes 9 and 10 of Bonterra's audited annual consolidated financial statements for the year ended December 31, 2009 and under the heading "Liquidity and Capital Resources" in Bonterra's management discussion and analysis, contained on pages 50 to 53 of the Company's 2009 Annual Report. The financial statements and management discussion and analysis are incorporated herein by reference.

Records

Bonterra's records are generally in accordance with those required to be maintained by a dividend-paying corporation incorporated under the *Business Corporations Act* (Alberta). All such records are kept at its offices in Calgary, Alberta.

Personnel

At the date of this report, Bonterra employed a total of 25 persons and contracted numerous field operations personnel.

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of Bonterra in a manner materially different than they would affect other oil and natural gas corporations or trusts of similar size.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (NEB). Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the NEB and the issuance of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

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

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based, mainly in the case of removals exceeding two years, on such factors as reserve availability, transportation arrangements, and market considerations.

Export from Canada

In order to export oil or natural gas from Canada, certain approvals are required from the NEB and the Government of Canada. The approval(s) required are dependent on the hydrocarbon substance being exported and the length of the proposed export arrangement.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil 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. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, commodity prices, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects, although the trend is toward eliminating these types of programs in favour of long-term programs which enhance predictability for producers. Oil and natural gas royalty holidays and reductions for specific wells will reduce the amount of Crown royalties paid by Bonterra to the provincial governments. The government of Alberta conducted a Crown royalty review in 2008 and announced a new royalty framework and then a new transitional royalty framework.

New Alberta Crown Royalty Framework (NRF)

The NRF rates vary with prices as well as productivity levels. With the current low commodity prices the new royalty rates should result in a reduction in the royalty rate the Company will pay for natural gas and an increased royalty rate for oil paid to the Province of Alberta.

On March 3, 2009, the Alberta government announced new short-term royalty incentive programs for the energy sector to encourage the development of new drilling projects in 2009. The program was introduced in response to the current global economic crisis and a slowdown in Alberta's drilling activity. This program will offer royalty credits per meter drilled as well as a cap on the royalty from the primary commodity produced of five percent for one year. This will apply to all wells drilled on crown land or placed on production between April 1, 2009 and March 31, 2010.

In June, 2009, the Alberta government announced that both incentive programs would be extended by one year to March 2011 to further stimulate the province's energy sector.

The province of Alberta is currently conducting an overall competitiveness review which is expected to result in changes to its royalty structure. The review is to look at all components of conventional operations, including regulatory efficiency, fiscal aspects, all aspects of taxation, availability of labour and other costs. The initial results of this competitiveness review were announced March 11, 2010 and may have an effect on the Company's profitability. As a result of the competitiveness study, royalty rates will be reduced but all actual reductions have not been disclosed at this time and they will take effect January 1, 2011.

Overall, any drilling conducted under the short-term royalty incentive programs will result in reduced royalty rates for the Company. Further details on royalty changes will be provided to shareholders after details are announced and as the Company assesses the impacts to its business.

Canadian Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties, the suspension or revocation of necessary licenses and authorizations, restrictions on the transfer of well and facility sites and civil liability for pollution damage. In Alberta, environmental compliance has been governed by the Alberta Environmental Protection and Enhancement Act (AEPEA) since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, the AEPEA also imposes certain new environmental compliance, reporting and monitoring responsibilities and stricter environmental standards on oil and natural gas operators in Alberta and in certain instances also imposes greater fines and penalties for violations. As well, the AEPEA permits greater public involvement in environmental assessment and enforcement.

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.

Oil and Natural Gas Prices/Foreign Exchange Rates

Bonterra's results of operations and financial condition are dependent on the prices received for their oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are

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

Exploitation and Development

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

Operations

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

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

Capital Investment

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

Debt Service

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 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.

Delay in Cash Payments

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

Reserves

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

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

Investment Eligibility

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

Environmental Concerns

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. Additionally, the potential impact on Bonterra's operations and business of the ratification by the federal government of the

Kyoto Protocol with respect to instituting reductions of greenhouse gases is difficult to quantify at this time as specific measures for meeting Canada's commitments have not been developed.

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

Reliance on Management

Shareholders will be dependent on the management of Bonterra in respect of the administration and management of all matters relating to Bonterra and its operations and administration. The loss of the services of key individuals could have a detrimental effect on Bonterra. Bonterra currently operates approximately 85.1 percent of its total daily production. Investors who are not willing to rely on the management of Bonterra should not invest in the common shares.

Dividends

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

Depletion of Reserves

Bonterra has certain unique attributes which 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 therefore its decline rate is a lower rate than many other industry participants. Bonterra will be retaining some 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.

Return of Capital

Common shares will have no value when reserves from Bonterra's properties can no longer be economically produced or marketed and, as a result, cash dividends do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment. Shareholders will have to obtain the return of capital invested out of cash flow derived from their investments in the common shares during the period when reserves can be economically recovered.

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 to the interests of Bonterra. No assurances can be given that opportunities identified by such board members will be provided to Bonterra.

Changes in Legislation

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.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth selected consolidated financial information of Bonterra.

	2009	2008	2007
Financial (\$ 000s, except \$ per share/unit)			
Revenue – realized oil and gas	85,712	121,730	96,431
Cash flow from operations	38,893	69,570	51,433
Per share / unit basic	2.16	4.07	3.04
Per share / unit diluted	2.15	4.06	3.04
Payout ratio ⁽¹⁾	79%	77%	87%
Funds Flow ⁽²⁾	66,504	70,448	53,815
Per share / unit basic	3.69	4.13	3.18
Per share / unit diluted	3.67	4.12	3.18
Payout ratio ⁽¹⁾	46%	76%	83%
Cash payments per share/unit ⁽¹⁾	1.70	3.12	2.64
Net earnings	68,563	55,426	30,350
Per share / unit basic	3.81	3.25	1.79
Per share / unit diluted	3.78	3.23	1.79
Capital expenditures and acquisitions (net of disposals)	5,640	45,407	19,300
Total assets	293,987	265,301	142,326
Working capital deficiency	10,162	23,878	58,766
Long-term debt	59,823	79,910	-
Shareholders'/unitholders' equity	118,874	56,777	44,376
Operations			
Oil and liquids (<i>barrels per day</i>)	3,141	3,073	3,113
Natural gas (<i>MCF per day</i>)	11,120	7,637	6,627
Total BOE per day	4,994	4,346	4,218

	2009			
	4 th	3 rd	2 nd	1 st
Financial (\$ 000s, except \$ per share)				
Revenue – realized oil and gas sales	24,946	20,965	20,501	19,300
Cash flow from operations	13,673	9,350	9,238	6,632
Per share basic	0.76	0.50	0.52	0.38
Per share diluted	0.75	0.50	0.52	0.38
Payout ratio ⁽¹⁾	66%	87%	77%	94%
Funds Flow ⁽²⁾	37,595	10,753	9,780	8,376
Per share basic	2.07	0.58	0.55	0.49
Per share diluted	2.06	0.57	0.55	0.49
Payout ratio ⁽¹⁾	24%	76%	73%	74%
Cash payments per share ⁽¹⁾	0.50	0.44	0.40	0.36
Net earnings	52,136	5,790	4,544	6,093
Per share basic	2.88	0.32	0.26	0.35
Per share fully diluted	2.85	0.32	0.26	0.35
Capital expenditures and acquisitions (net of disposals)	(16,976)	17,660	2,255	2,701
Total assets	293,987	273,543	258,393	260,732
Working capital deficiency	10,162	14,455	13,989	14,909
Long-term debt	59,823	81,386	71,573	89,383
Shareholders' equity	118,874	74,025	72,332	56,377
Operations				
Oil and liquids (<i>barrels per day</i>)	3,182	3,084	3,029	3,268
Natural gas (<i>MCF per day</i>)	10,193	10,881	11,551	11,877
Total BOE per day	4,881	4,898	4,954	5,245

	2008			
	4 th	3 rd	2 nd	1 st
Financial (\$000, except \$ per share / unit)				
Revenue – realized oil and gas sales	22,613	34,226	34,398	30,493
Cash flow from operations	10,336	22,492	20,530	16,212
Per share / unit basic	0.59	1.31	1.21	0.96
Per share / unit diluted	0.59	1.30	1.20	0.96
Payout ratio ⁽¹⁾	105%	73%	69%	73%
Funds flow ⁽²⁾	8,546	22,492	21,352	18,058
Per share / unit basic	0.50	1.31	1.25	1.07
Per share / unit diluted	0.50	1.30	1.24	1.06
Payout ratio ⁽¹⁾	124%	73%	67%	65%
Cash payments per share/unit ⁽¹⁾	0.62	0.96	0.84	0.70
Net earnings	10,585	21,125	12,912	10,804
Per share / unit basic	0.62	1.23	0.76	0.64
Per share / unit diluted	0.62	1.22	0.75	0.64
Capital expenditures and acquisitions (net of disposals)	30,405	6,038	2,543	6,421
Total assets	265,301	150,120	153,247	150,169
Working capital deficiency	23,878	47,499	57,148	57,810
Long-term debt	79,910	-	-	-
Shareholders/unitholders' equity	56,777	57,623	46,612	48,136
Operations				
Oil and liquids (<i>barrels per day</i>)	3,055	2,998	3,009	3,153
Natural gas (<i>MCF per day</i>)	8,817	7,233	7,272	7,139
Total BOE per day	4,525	4,204	4,221	4,343

⁽¹⁾ Cash dividend/disbursement payments per share/unit are based on payments made in respect of production months as opposed to the month paid.

⁽²⁾ Funds flow is not a recognized measure under GAAP. For these purposes, the Company defines funds flow as funds provided by operations before changes in non-cash operating working capital items but including gain on sale of property, adjustments of investment tax credit receivable, and excluding restricted cash and asset retirement obligations settled.

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

Management's discussion and analysis of its financial condition and results of operations for the year ended December 31, 2009, as contained on pages 27 to 53 of the Company's Annual Report for the year ended December 31, 2009 is incorporated by reference in this Annual Information Form.

DIVIDENDS / DISTRIBUTIONS TO SHAREHOLDERS / UNITHOLDERS

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.

The following cash distributions/dividends were paid by Bonterra since 2007:

<u>Month of Record and Payment Date</u>	<u>Amount per Trust Unit/Share</u>
January, 2007 ⁽¹⁾	\$0.22
February, 2007	\$0.22
March, 2007	\$0.22
April, 2007	\$0.22
May, 2007	\$0.22
June, 2007	\$0.22
July, 2007	\$0.22
August, 2007	\$0.22
September, 2007	\$0.22
October, 2007	\$0.22
November, 2007	\$0.22
December, 2007	\$0.22
January, 2008 ⁽¹⁾	\$0.22
February, 2008	\$0.22
March, 2008	\$0.23
April, 2008	\$0.25
May, 2008	\$0.25
June, 2008	\$0.27
July, 2008	\$0.32
August, 2008	\$0.32
September, 2008	\$0.32
October, 2008	\$0.32
November, 2008 ⁽²⁾	\$0.26
December, 2008	\$0.20
January, 2009	\$0.16
February, 2009	\$0.12
March, 2009	\$0.12
April, 2009	\$0.12
May, 2009	\$0.12
June, 2009	\$0.14
July, 2009	\$0.14
August, 2009	\$0.14
September, 2009	\$0.14
October, 2009	\$0.16
November, 2009	\$0.16
December, 2009	\$0.16

<u>Month of Record and Payment Date</u>	<u>Amount per Trust Unit/Share</u>
January, 2010	\$0.18
February, 2010	\$0.18
March, 2010	\$0.18

Notes:

- (1) The record date for the distribution was December 31 of the prior year.
(2) The November 28, 2008 payments and all subsequent payments are classified as dividends. All payment amounts prior to November 28, 2008 were classified as distributions.

The historical distribution/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.

Issued	2009		2008	
	Number	Amount (\$ 000s)	Number	Amount (\$ 000s)
Common Shares				
Balance, beginning of year	17,257,603	99,530	-	-
Issued pursuant to private placement	1,068,000	17,996	-	-
Issued on acquisition of Cobalt	201,438	3,207	-	-
Issued pursuant to Company share option plan	92,600	1,898	-	-
Transfer of contributed surplus to share capital	-	103	-	-
Issue costs for private placement	-	(1,046)	-	-
Future tax effect of share issue costs	-	267	-	-
Issued on reorganization to a corporation	-	-	17,257,603	99,530
Balance, end of year	18,619,641	121,955	17,257,603	99,530

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 option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,861,964 common shares (2008 – 1,725,760). The exercise price of each option granted equals 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, 2009 and changes during the year is presented below:

	December 31, 2009	
	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	1,390,500	\$ 20.50
Options granted	33,000	14.90
Options exercised	(92,600)	20.50
Outstanding at end of period	1,330,900	\$ 20.36
Options exercisable at end of period	370,900	\$ 20.50

The following table summarizes information about common stock options outstanding at December 31, 2009:

Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding At 12/31/09	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/09	Weighted-Average Exercise Price
\$14.90	33,000	3.1 years	\$14.90	-	\$ -
20.50	1,297,900	2.9 years	20.50	370,900	20.50
\$14.90-20.50	1,330,900	2.9 years	\$20.36	370,900	\$20.50

MARKET FOR SECURITIES

The outstanding shares are listed and posted for trading on the Toronto Stock Exchange (the “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 2009	\$17.25 to \$20.00	692,780
February, 2009	\$14.16 to \$17.90	424,384
March, 2009	\$13.50 to \$15.80	372,780
April, 2009	\$14.87 to \$17.99	324,409
May, 2009	\$17.35 to \$21.24	145,123
June, 2009	\$21.03 to \$23.40	284,016
July, 2009	\$20.10 to \$25.99	656,211
August, 2009	\$23.40 to \$26.00	425,816
September, 2009	\$24.23 to \$26.36	333,834
October, 2009	\$26.00 to \$29.50	866,838
November, 2009	\$28.45 to \$31.14	580,709
December, 2009	\$29.80 to \$36.44	591,752

On December 31, 2009, the closing price of BNE shares on the TSX was \$34.66.

The Company as of December 31, 2009 had 18,619,641 shares outstanding.

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 below:

Name and Municipality of residence	Position Since	Principal Occupation for Past Five Years
Gary J. Drummond ⁽¹⁾⁽²⁾ Nassau, Bahamas	Director August, 1999	Mr. Drummond is a private investor and a director of several entities including Comaplex Minerals Corp. and Pine Cliff Energy Ltd and a Trustee for Heating Oil Partners Income Fund
George F. Fink Calgary, Alberta	CEO and Chairman January, 1981	Bachelor of Commerce degree, Chartered Accountant. Engaged part-time as the President, CEO and a director of Comaplex Minerals Corp., Pine Cliff Energy Ltd. and First National AlarmCap Income Fund.

Name and Municipality of residence	Position Since	Principal Occupation for Past Five Years
Randy M. Jarock Calgary, Alberta	President and COO December, 2008	B.Sc. in Petroleum Engineering. Formally COO since February 2001. Engaged part-time as COO for Pine Cliff Energy Ltd.
Carl R. Jonsson ⁽¹⁾⁽²⁾ Vancouver, B.C.	Director January, 1981	Lawyer and Principal with the Vancouver law firm of Tupper, Jonsson & Yeadon. Also a director of Comaplex Minerals Corp., Pine Cliff Energy Ltd., Caledonia Mining Corp., Comet Industries Ltd., Astorius Resources Ltd., Acrex Ventures Ltd., Dolly Varden Resources Inc., and Alder Resources Ltd.
Garth E. Schultz Calgary, Alberta	Vice President, Finance, CFO and Secretary November, 1994	Chartered Accountant. Engaged part-time as CFO of Comaplex Minerals Corp. and Pine Cliff Energy Ltd.
F.W. Woodward ⁽¹⁾⁽²⁾ Calgary, Alberta	Director January, 1981	Private investor. Mr. Woodward is a director of Comaplex Minerals Corp. and Pine Cliff Energy Ltd.

Notes:

⁽¹⁾ Member of the Director Affairs Committee.

⁽²⁾ Member of the Audit Committee. Chaired by F.W. Woodward.

The Executive, Compensation and Reserve committees consist of all four board members.

All of the directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 4,798,613 common shares representing approximately 25.7 percent of the issued and outstanding units of Bonterra as at the date of this report.

AUDIT COMMITTEE INFORMATION

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

Audit Committee Charter

The Audit Committee Charter is attached as Schedule "A" to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of Gary J. Drummond, Carl R. Jonsson and F. William Woodward. Each director is considered "independent" and "financially literate" (as such terms are defined in MI 52-110).

Relevant Education and Experience

Each member of the Audit Committee is financially literate, i.e., has the ability to read and understand financial statements. 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 below:

Name	Education and Experience
F. William Woodward (Chairman)	<ul style="list-style-type: none"> • Private investor. • Director of corporations such as Bonterra Energy Corp., Comaplex Minerals Corp. and Pine Cliff Energy Ltd., and a member of the Audit Committee of each of those corporations. • Former Director and member of the Audit Committee for several public companies.
Gary J. Drummond	<ul style="list-style-type: none"> • Lawyer, businessman and private investor. • Director of several public corporations and a member of the Audit Committee of certain of those corporations. • Trustee of Heating Oil Partners Income Fund (a public income trust). • 35 years of extensive experience directly related to all aspects of reading and understanding financial statements and matters. • Former President and CEO of Direct Energy Marketing Limited (a public resource company). • BA (Economics) and Law Degree.
Carl R. Jonsson	<ul style="list-style-type: none"> • LLB. Securities/corporate lawyer for many years, including extensive involvement in numerous business transactions. Principal of the Vancouver law firm of Tupper, Jonsson & Yeadon. • Currently Director and officer of numerous public corporations and a member of the Audit Committee of many of them. • Many years of extensive experience related to the supervision of the preparation of financial statements and CFO of public companies.

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 Corp., on behalf of the Trust. 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 \$7,500 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 are as follows:

Financial Year Ending December 31	Audit and Audit Related Fees	Tax Planning, Quarterly Review Fees and Compliance and Other Accounting Issues	All Other Fees
2009	\$ 165,731	\$ 6,360	\$ -
2008	\$ 207,396	\$ 5,300	\$ -

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.

MATERIAL CONTRACTS

Following are the contracts, other than contracts entered into in the ordinary course of business that are material to Bonterra.

- Banking Agreements

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 15, 2010, which relates to the Annual General Meeting of Unitholders to be held on May 26, 2010. 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, 2009 and 2008, which are included in Bonterra's Annual Report for the year ended December 31, 2009.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs 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. Kirsten Kulyk
Phone: (403) 750-2554
Facsimile: (403) 265-7488
Email: kkulyk@bonterraenergy.com

SCHEDULE "A"

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 over seeing 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 Administrator or of an affiliate of the Administrator.

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 over seeing. 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 generally accepted accounting principles (GAAP). 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 generally accepted auditing standards, that the financial statements present fairly, in all material respects, the financial position, results of operations and cash flows of the Company in accordance with GAAP.

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 and Chief Executive Officer;
- (ii) Vice President, Finance and Chief Financial Officer.

The Chairman of the Board, executive management of the Administrator 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 Administrator's 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 Trust.
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.