

BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2010

March 22, 2011

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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;

"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 3, 2011 and effective December 31, 2010 utilizing commodity price forecasts of Sproule dated December 31, 2010;

"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 ENERGY CORP.

Bonterra Energy Corp.

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

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

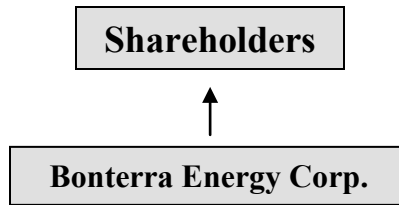
The Company's primary focus is to maximize total return to shareholders by growing production and maintaining and enhancing cash dividends through the optimum utilization and development of existing crude oil and natural gas properties and acquisition and development of new producing or undeveloped properties.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

Transfer Agent and Registrar

The Registrar and Transfer Agent for the common shares is 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.

Organization Chart

At December 31, 2010, the structure of Bonterra was as set forth below:



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

GENERAL DEVELOPMENT OF THE BUSINESS

Historical Overview

Bonterra Energy Corp. was formed effective January 1, 2010 when 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.

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.

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 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.

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.

Property and Corporate Acquisitions and Dispositions in 2010, 2009 and 2008

In February 2010, the Company disposed of its Southeast Saskatchewan Pinto property. The proceeds of disposition were \$5,534,000 cash. At the time of disposition, the Company had a net book value of \$120,000 for the property and had an asset retirement obligation related to the property of \$371,000 that was transferred resulting in a gain on sale of property of \$5,785,000. Production from this property was approximately 60 BOE per day consisting primarily of light, sweet crude oil. In addition, during the third

quarter of 2010 the Company disposed of non-producing land for proceeds of \$700,000. The Company had no capital costs associated with this land.

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.

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 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.

Canadian Federal Government's Taxation of Income Trusts

On November 12, 2008, Bonterra Energy Income Trust converted to a corporation and thus was 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, 2010 contained in the Sproule Report dated February 3, 2011.

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".

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. Tables may not add due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices: 1) Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2010 pricing assumptions; and 2) Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.

FORM 51-101F1 PART 2.1(1)
SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

Reserve Category:	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED						
Developed Producing	15,594.4	13,884.1	32,552	29,973	1,400.7	987.8
Developed Non-Producing	206.1	186.1	507	451	12.6	9.8
Undeveloped	4,693.0	3,926.0	5,441	4,948	251.7	187.1
TOTAL PROVED	20,493.5	17,996.1	38,500	35,373	1,665.0	1,184.6
PROBABLE	7,708.2	6,341.3	15,192	13,860	581.7	407.0
TOTAL PROVED PLUS PROBABLE	28,201.7	24,337.4	53,692	49,232	2,246.7	1,591.6

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, 2010
FORECAST PRICES AND COSTS

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

(\$ Millions) Reserve Category:						Future Net Value
	0%	5%	10%	15%	20%	10%/yr (\$/BOE)
PROVED						
Developed Producing	1,097.7	656.9	479.9	385.3	326.0	24.15
Developed Non-Producing	14.4	10.7	8.6	7.2	6.2	31.65
Undeveloped	207.1	135.8	93.1	65.4	46.5	18.85
TOTAL PROVED	1,319.2	803.5	581.6	457.9	378.7	23.19
PROBABLE	644.5	251.8	132.1	82.0	56.1	14.58
TOTAL PROVED PLUS PROBABLE	1,963.7	1,055.2	713.6	540.0	434.8	20.91

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, 2010
FORECAST PRICES AND COSTS

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

(\$ Millions)		0%	5%	10%	15%	20%
Reserves Category:						
PROVED						
Developed Producing		929.5	585.3	441.9	362.7	311.5
Developed Non-Producing		10.8	8.3	6.8	5.8	5.1
Undeveloped		155.3	100.3	67.4	46.1	31.6
TOTAL PROVED		1,095.5	693.9	516.1	414.7	348.2
PROBABLE		483.5	188.5	98.7	61.2	41.9
TOTAL PROVED PLUS PROBABLE		1,579.0	882.3	614.8	475.9	390.1

The Company only operates in Canada.

FORM 51-101F1 PART 2.1(3)(b)
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

(\$ Millions)						Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Reserves Category:	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment/ Other Costs			
Proved	2,537.6	313.6	738.7	134.9	31.1	1,319.2	223.8	1,095.5
Proved Plus Probable	3,649.0	497.9	1,003.6	148.6	35.1	1,963.7	384.7	1,579.0

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, 2010
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)	558.4	23.91
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)*	23.2	13.47
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	683.1	21.64
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)*	30.5	11.90

* 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
2010	77.81	4.16	57.04	84.21	1.0	0.971
FORECAST						
2011	93.08	4.04	62.44	95.32	1.5	0.932
2012	93.85	4.66	62.95	96.11	1.5	0.932
2013	93.43	4.99	62.67	95.68	1.5	0.932
2014	93.54	6.58	62.75	95.79	1.5	0.932
2015	94.95	6.69	63.69	97.24	1.5	0.932

Crude oil, natural gas and liquid prices escalate at 1.5 percent thereafter.

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

The Company's weighted average historical prices by production type for the 2010 financial year are as follows:

- Light and Medium Crude Oil per barrel \$74.76
- Natural Gas per Mcf \$ 4.14
- Natural Gas Liquids per barrel \$47.11

**PART IV – RECONCILIATION OF CHANGES IN RESERVES
RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
AS OF DECEMBER 31, 2010
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)	(Mmcf)	(Mboe)	(Mboe)	(Mboe)
December 31, 2009	19,220	8,348	27,568	36,642	12,896	49,539	25,327	10,497	35,824
Extension	2,984	1,932	4,916	2,706	1,668	4,374	3,435	2,210	5,645
Improved recovery	0	0	0	0	0	0	0	0	0
Technical revisions	1,474	(1,964)	(490)	3,512	681	4,193	2,059	1,851	209
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(179)	(34)	(213)	(318)	(58)	(376)	(232)	44	(276)
Economic factors	74	9	83	(202)	4	(198)	40	10	50
Production	(1,414)	0	(1,414)	(3,840)	0	(3,840)	(2,054)	0	(2,054)
December 31, 2010	22,159	8,290	30,448	38,500	15,192	53,693	28,575	10,822	39,397

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, 2008	2,808	2,808	Opening balance (cumulative and first attributed are equal).
2008	0	2,258	Of the 2007 PUDs, 550 PUDs relate to wells that were drilled and were converted to proved developed producing.
2009	1,978	3,284	Of the 2008 PUDs, 952 PUDs relate 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.
2010	2,359	4,693	Of the 2009 PUDs, 1,184 PUDs relate to wells that were drilled and were converted to proved developed producing. 234 PUDs were added through Technical Revisions. The Company received an increase in PUDs of 2,359 related to the Cardium horizontal drilling program initiated by the Company.

Probable Light and Medium Oil Gross Reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2008	855	855	Opening balance (cumulative and first attributed are equal).
2008	42	605	Of the 2007 PBUDs, 292 PBUDs relate 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	4,079	4,147	Of the 2008 PBUDs, 537 PBUDs relate 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.
2010	1,592	2,619	Of the 2009 PUDs, 2,517 PBUDs relate to wells that were drilled and were converted to proved developed producing. The Company received a decrease in PBUDs of 601 due to Technical Revisions. The Company received an increase of 1,592 PBUDs related to the Cardium horizontal drilling program initiated by the Company.

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

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2008	3,355	3,355	Opening balance (cumulative and first attributed are equal).
2008	763	3,594	Of the 2007 PUDs, 524 PUDs relate 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 relate 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.
2010	2,083	5,441	Of the 2009 PUDs, 530 PUDs relate to wells that were drilled and were converted to probable developed producing. The Company received an increase in PUDs of 109 due to Technical Revisions. The Company received an increase of 2,083 PBUDs related to the Cardium horizontal drilling program initiated by the Company.

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

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2008	1,031	1,031	Opening balance (cumulative and first attributed are equal).
2008	1,622	2,574	Of the 2007 PBUDs, 79 PBUDs relate 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 relate 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.
2010	1,366	4,128	Of the 2009 PBUDs, 1,018 PBUDs relate to wells that were drilled and were converted to probable developed producing. The Company received a decrease in PBUDs of 104 due to Technical Revisions. The Company received an increase of 1,366 PBUDs related to the Cardium horizontal drilling program initiated by the Company.

Proved Coal Bed Methane Gross Reserves (Mmcf)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2008	-	-	Opening balance (cumulative and first attributed are equal).
2008	-	-	No PUD adjustments.
2009	-	-	No PUD adjustments.
2010	-	-	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, 2008	186	186	Opening balance (cumulative and first attributed are equal).
2008	-	112	Of the 2007 PUDs, 74 PUDs relate 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.
2010	115	251	Of the 2009 PUDs, 27 PUDs relate to wells that were drilled and were converted to proved developed producing. 27 PUDs were deleted through Technical Revisions. The Company received an increase in PUDs of 115 related to the Cardium horizontal drilling program initiated by the Company.

Probable Natural Gas Liquids Gross Reserves (MBbl)

Year	1 st Attributed	Cumulative	Description
Opening balance January 1, 2008	54	54	Opening balance (cumulative and first attributed are equal).
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.
2010	73	136	Of the 2009 PBUDs, 44 PBUDs relate to wells that were drilled and were converted to proved developed producing. 13 PBUDs were deleted through Technical Revisions. The Company received an increase in PBUDs of 73 related to the Cardium horizontal drilling program initiated by the Company.

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 2010 Annual Report.

Future Development Costs

\$ Millions	Forecast Prices and Costs	
	Proved	Proved Plus Probable
Year		
2011	36.6	43.0
2012	37.6	43.4
2013	44.7	44.1
2014	16.1	18.0
2015	0	0
Total Undiscounted	134.9	148.6

The above future development costs will be funded primarily from 2011 to 2014 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, British Columbia and Saskatchewan. In 2010, production volumes from Bonterra's properties were approximately 69 percent crude oil and NGLs and 31 percent natural gas on a BOE basis. During the year ended December 31, 2010, Bonterra's oil and natural gas properties yielded average production of 5,628 BOE per day (2009 - 4,994 BOE per day, 2008 – 4,346 BOE per day). As at December 31, 2010 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 39,397 MBOE.

Pembina Area, West Central Alberta.

Properties

Pembina is Bonterra's main property. It is the Company's largest producing asset and represents 94.3 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 approximately 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 Pembina. 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 resulted in increased reserves and maximized income from the properties and a reduction in the decline rate.

In 2008, Bonterra began 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 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.

In 2010, Bonterra expanded its horizontal drilling program further; both in the halo area of Pembina and Willesden Green and in the main Pembina pool. Bonterra drilled 22 operated Pembina Cardium horizontal wells (20.05 net) during 2010 in the halo area and has produced in total approximately 744,512 barrels of oil from these wells since the first horizontal well came on production in February 2009. Bonterra's working interest in the wells drilled in 2010 ranges from 68.18 to 100 percent, averaging 91.12 percent.

Bonterra also participated in drilling five gross (0.75 net) non-operated, horizontal Berrymoor Cardium Unit wells in the main Pembina Cardium field and is pleased to present the following gross production volumes to February 6, 2011 for the wells that are currently on production.

Location	Days on Production	Cumulative Oil Production (bbls)	Initial Oil Production 30 days (bbls/day)	Current Day Oil (bbls/day)
10-10-049-06 W5	34	8,542.1	245	308.9
12-12-049-06 W5	21	5,633.8	268*	347.8
02-07-049-06 W5	84	2,118.8	235	282.2
04-12-049-06 W5	126	25,511.6	187	164.2
05-31-049-05 W5**	113	3,655.1	45	29.2

* 21 day rate

** Well was not frac'd

The Company's 2011 capital development plans include drilling at least 20 gross wells with the majority targeted in the halo Area of the Pembina Cardium and Willesden Green fields with the remainder in the main pool of the Pembina Cardium.

The implementation of two CO₂ pilot projects in the Cardium zone by other industry operators in the area points to the potentially 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 monitor 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 production from the main Pembina field including gathering systems, satellites, batteries, water disposal plants, pipelines, compressor stations and gas plants. Increased industry activity in the Pembina field is starting to cause facility constraints and the Company continues to work to mitigate capacity issues. 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 some 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. Emulsion from halo well production is processed through Company operated gathering systems and batteries with extracted solution gas being processed at third party gas plants which currently have excess capacity.

Prespatou Area, Northeast British Columbia

The Prespatou area of northeast British Columbia (NEBC) consists almost entirely of natural gas and associated natural gas liquids with production of approximately 440 BOE per day.

As natural gas prices have remained depressed in 2010, the Company has focused on cost minimization and low cost optimizations to maximize profitability in the area. The Company has evaluated the geology of the entire area in which it holds interest to assess and identify potential drilling and workover opportunities. The 2011 development plans will focus on continued optimization of production from existing well bores. A drilling inventory has been established and a drilling program will be conducted should the price of natural gas improve.

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. 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.

Shaunavon Area, Southwest Saskatchewan

Properties

Bonterra's Shaunavon properties are located in the Chambery field and produce medium density crude oil from the upper Shaunavon formation currently under waterflood. Current production is 120 BOE per day (net). The wells in this area are generally long-life with stable, low-decline production profiles and Bonterra is optimizing the existing waterflood program to further increase profitability from the existing property.

Facilities

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

Well Count

The wells in which Bonterra had an interest as at December 31, 2010 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	712.0	433.2	138.0	71.0	48.0	17.1	39.0	34.0	760.0	450.3	177.0	104.9
BC	-	-	75.0	28.5	-	-	14.0	8.6	-	-	89.0	37.1
SK	30.0	26.1	4.0	4.0	7.0	6.2	-	-	37.0	32.3	4.0	4.0
Total	742.0	459.3	217.0	103.5	55.0	23.3	53.0	42.5	797.0	482.7	270.0	146.0

Properties with No Attributable Reserves

The Company's property with no attributable reserves consists of approximately 57,419 gross and 30,807 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 6,632 gross (2,069 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 1.5 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 1,067 gross wells (628.7 net). The total amount of costs expected to be incurred is \$62,579,000 (2009 - \$64,482,000) prior to discounting and \$8,270,000 (2009 - \$8,904,000) discounted at 10 percent. This includes \$5,133,000 (2009 - \$5,453,000 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
2011	616
2012	661
2013	703

Of the above amounts \$Nil, \$36,000 and \$68,000 of the 2011, 2012 and 2013 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	\$ 25,441
Eligible capital expenditures	7	6,849
Share issue costs	20	1,424
Canadian oil and gas property expenditures	10	19,074
Canadian development expenditures	30	109,642
Canadian exploration expenditures	100	11,140
SR&ED expenditures	100	39,985
Income tax losses carried forward ⁽¹⁾	100	222,596
		<u>\$436,151</u>

⁽¹⁾ Income tax losses carried forward expire in the following years; 2024 - \$3,347,000, 2025 - \$7,532,000, 2026 - \$46,671,000, 2027 - \$117,189,000, 2028 - \$34,726,000, 2029 - \$13,131,000.

In addition to the preceding pools, the Company also has \$27,670,000 (December 31, 2009 - \$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 \$141,417,000 (December 31, 2009 - \$143,061,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

The Company currently anticipates that these tax pools extend its tax horizon beyond 2018.

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)	2010	2009
Land	-	5,184
Acquisitions	-	7,105
Disposals	(6,234)	(30,191)
Exploration and development costs	76,914	22,912
Net petroleum and natural gas capital expenditures	<u>70,680</u>	<u>5,640</u>

Exploration and Development Activities

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

	2010					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	30	22.09	-	-	30	22.09
Natural gas	1	0.11	-	-	1	0.11
Dry	-	-	-	-	-	-
Total	31	22.20	-	-	31	22.20
Success rate	100%	100%	-	-	100%	100%

	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%

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

Production Estimates

	2011		
	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)
Pembina, Alberta	4,230	7,629	327
British Columbia	-	2,811	25
Saskatchewan	161	128	-
Other Alberta	171	563	39
	4,562	11,131	391

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 2010

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	3,080	77.43	7.68	19.04	50.71
2 Quarter	3,607	73.26	7.20	17.52	48.54
3 Quarter	3,576	70.85	7.29	20.18	43.39
4 Quarter	4,062	78.97	6.32	20.08	52.57
Natural Gas (Mcf)					
1 Quarter	10,038	5.11	0.42	1.26	3.43
2 Quarter	11,157	3.97	0.12	0.94	2.91
3 Quarter	10,674	3.74	0.18	1.09	2.48
4 Quarter	10,214	3.78	0.13	0.99	2.66
Natural Gas Liquids (Bbls)					
1 Quarter	265	48.33	13.72	11.89	22.72
2 Quarter	267	47.12	13.48	11.27	22.37
3 Quarter	314	44.24	13.00	12.60	18.64
4 Quarter	316	48.88	13.73	12.43	22.73

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

	2010		
	Oils and NGLs (Bbls per day)	Natural Gas (MCF per day)	Total (BOE per day)
Pembina, Alberta	3,564	6,607	4,665
Saskatchewan	172	269	217
British Columbia	22	2,971	517
Other Alberta	117	674	229
	3,875	10,521	5,628

Lease Holdings

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

	2010		2009	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	172,749	109,944	172,907	109,710
Saskatchewan	6,881	5,640	14,779	12,846
British Columbia	61,330	21,217	73,194	28,509
	240,960	136,801	260,880	151,065

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, 2010 and 2009 are as follows:

	2010		2009	
	\$ 000s	% of Total Revenue	\$ 000s	% of Total Revenue
Crude Oil and NGLs	103,061	87	68,850	80
Natural Gas	15,919	13	16,862	20
	118,980	100	85,712	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 total return to shareholders over the long-term by growing production and maintaining and enhancing cash dividends to shareholders through the optimum utilization and development of existing crude oil and natural gas properties and acquisition or development of new producing or undeveloped properties.

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

Dividends

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

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

See "Dividends/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, a subordinated promissory note and borrowing from related parties. Details of the banking arrangement is contained in Note 9 of Bonterra's audited annual consolidated financial statements for the year ended December 31, 2010 and under the heading "Liquidity and Capital Resources" in Bonterra's management discussion and analysis, contained on pages 19 to 48 of the Company's 2010 Annual Report. The financial statements and management discussion and analysis are incorporated herein by reference.

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.

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 National Energy Board (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.

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 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.

Bonterra does not export directly.

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 has since made several changes to royalties in 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 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 conducted an overall competitiveness review which resulted in changes to its royalty structure. On March 11, 2010, the Alberta Government enacted changes applicable to crown royalties. Highlights of the changes are:

- the temporary five percent royalty incentive programs became a permanent feature of the royalty system; for the first 50,000 to 100,000 bbls of oil equivalent production in 18 to 48 months depending on depth for oil wells and 500 Mmcf equivalent production of gas in 48 months for a gas well.
- maximum royalty rates for conventional oil was reduced to 40 percent from 50 percent;
- maximum royalty rates for natural gas will be reduced to 36 percent from 50 percent;
- the \$200-per-metre-drilled royalty credit incentive program that was in place was continued until March 31, 2011;
- the Transitional Royalty Framework will continue until December 31, 2013 but effective January 1, 2011, no new wells will be allowed to be drilled under the "Transitional Framework"; and
- wells already under the "Transitional Framework" system will have the option to remain or switch to the "New Royalty Framework" effective January 2011.

As a result of the changes enacted under the competitiveness study, the Company's royalties will be reduced and have a positive effect on the Company's profitability.

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.

Alberta

Environmental legislation in the Province of Alberta has largely been consolidated into the *Environmental Protection and Enhancement Act* (Alberta), the *Water Act* (Alberta), and the *Oil and Gas Conservation Act* (Alberta). These statutes impose environmental standards, require compliance, reporting and monitoring obligations, and in certain instances also impose greater fines and penalties for violations. In addition, the emission reduction requirements in the *Climate Change and Emissions Management Act* (Alberta) came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting certain levels of GHG emissions per year must report such emission to Alberta Environment and Environment Canada while facilities emitting even higher specific levels of GHG emissions per year must reduce their emissions intensity.

British Columbia

British Columbia's *Environmental Assessment Act* creates an environmental assessment process for reviewing the potential environmental impact of major energy projects within the province. On February 27, 2007, the Government of British Columbia unveiled the BC Energy Plan, which outlines the province's energy strategy. The BC Energy Plan sets targets for reducing GHG emissions, promoting investments in innovation, and sustainable environmental management. The BC Energy Plan's objectives are to achieve clean energy through conservation and energy efficient practices, and to increase competitiveness in order to attract new investment in the oil and natural gas industry. In furtherance of these initiatives, the

Government of British Columbia introduced the *Carbon Tax Act* on July 1, 2008. The carbon tax applies to fuels such as gasoline, diesel, natural gas, propane and coal, and it is revenue-neutral, meaning tax revenues will be returned to taxpayers through reductions in other provincial taxes.

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. The payment of such uninsured liabilities would reduce the funds available to it. The occurrence of a significant event that Bonterra is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bonterra's financial position, results of operations or prospects.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to

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

Legal Proceedings

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

Third Party Credit Risk

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

Operational Dependence

Other companies operate some of the assets in which Bonterra has an interest. As a result, Bonterra will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect its financial performance. Bonterra's return on assets operated by others will therefore depend upon a number of factors that may be outside of its control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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

Changes in Legislation and Canadian Tax Considerations

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

As Bonterra is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. Bonterra has reviewed its historical income tax returns with respect to the characterization of the costs incurred in the oil and natural gas business as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. Bonterra has filed or will file all required income tax returns and believes that it is full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

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

Annual Comparisons

Financial (\$000s, except \$ per share)	2010	2009	2008
Revenue – realized oil and gas	118,980	85,712	121,730
Funds Flow ⁽¹⁾	79,602	66,504	70,448
Per share basic	4.23	3.69	4.13
Per share diluted	4.12	3.67	4.12
Payout ratio ⁽²⁾	60%	46%	76%
Cash flow from operations	66,262	38,893	69,570
Per share basic	3.52	2.16	4.07
Per share diluted	3.42	2.15	4.06
Payout ratio ⁽²⁾	72%	79%	77%
Cash dividends per share ⁽²⁾	2.55	1.70	3.12
Net earnings ⁽³⁾	49,864	68,563	55,426
Per share basic	2.65	3.81	3.25
Per share diluted	2.58	3.78	3.23
Capital expenditures and acquisitions (net of disposals)	70,680	5,640	45,407
Total assets	335,144	293,987	265,301
Working capital deficiency	14,602	10,162	23,878
Long-term debt	85,386	59,823	79,910
Shareholders' equity	138,413	118,874	56,777
Operations			
Oil and liquids (barrels per day)	3,875	3,141	3,073
Natural gas (MCF per day)	10,521	11,120	7,637
Total BOE per day	5,628	4,994	4,346

⁽¹⁾ 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 and investments, adjustments of investment tax credit receivable, and excluding restricted cash and asset retirement obligations settled.

⁽²⁾ Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

⁽³⁾ Net earnings include gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 - \$10,820,000, 2009 - \$51,868,000, 2008 - \$Nil).

Quarterly Comparisons

Financial (\$000s, except \$ per share)	2010			
	4th	3rd	2nd	1st
Revenue – realized oil and gas	34,209	28,332	29,191	27,248
Funds Flow ⁽¹⁾	21,104	19,622	17,550	21,326
Per share basic	1.11	1.04	0.94	1.14
Per share diluted	1.08	1.01	0.91	1.11
Payout ratio ⁽²⁾	61%	63%	68%	50%
Cash flow from operations	16,987	17,558	16,644	15,073
Per share basic	0.89	0.93	0.89	0.81
Per share diluted	0.86	0.91	0.86	0.79
Payout ratio ⁽²⁾	74%	71%	72%	70%
Cash dividends per share ⁽²⁾	0.68	0.66	0.64	0.57
Net earnings ⁽³⁾	14,213	12,724	10,887	12,040
Per share basic	0.75	0.68	0.58	0.64
Per share diluted	0.73	0.66	0.56	0.63
Capital expenditures and acquisitions (net of disposals)	25,318	19,227	10,994	15,141
Total assets	335,144	318,493	307,934	305,440
Working capital deficiency	14,602	17,891	2,281	13,178
Long-term debt	85,386	73,901	78,434	63,097
Shareholders' equity	138,413	128,492	126,045	125,392
Operations				
Oil and liquids (barrels per day)	4,378	3,890	3,874	3,345
Natural gas (MCF per day)	10,214	10,674	11,157	10,038
Total BOE per day	6,080	5,669	5,733	5,018

⁽¹⁾ 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 and investments, adjustments of investment tax credit receivable, and excluding restricted cash and asset retirement obligations settled.

⁽²⁾ Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

⁽³⁾ Net earnings include gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2010 - \$10,820,000, 2009 - \$51,868,000).

Financial (\$000s, except \$ per share)	2009			
	4th	3rd	2nd	1st
Revenue – realized oil and gas	24,946	20,965	20,501	19,300
Funds Flow ⁽¹⁾	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 ⁽²⁾	24%	76%	73%	74%
Cash flow from operations	13,668	9,350	9,238	6,637
Per share basic	0.76	0.50	0.52	0.38
Per share diluted	0.75	0.50	0.52	0.38
Payout ratio ⁽²⁾	66%	87%	77%	94%
Cash dividends per share ⁽²⁾	0.50	0.44	0.40	0.36
Net earnings ⁽³⁾	52,136	5,790	4,544	6,093
Per share basic	2.88	0.32	0.26	0.35
Per share 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 (barrels per day)	3,182	3,084	3,029	3,268
Natural gas (MCF per day)	10,193	10,881	11,551	11,877
Total BOE per day	4,881	4,898	4,954	5,245

⁽¹⁾ 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 and investments, adjustments of investment tax credit receivable, and excluding restricted cash and asset retirement obligations settled.

⁽²⁾ Cash dividend payments per share are based on payments made in respect of production months as opposed to the month paid.

⁽³⁾ Net earnings include gains from the sale of properties and investments and recognition of investment tax credits before tax effect as follows: (2009 - \$51,868,000).

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

The financial statements and the management's discussion and analysis of its financial condition and results of operations for the year ended December 31, 2010, as contained on pages 19 to 48 of the Company's Annual Report for the year ended December 31, 2010 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 2008:

<u>Month of Record and Payment Date</u>	<u>Amount per Trust Unit/Share</u>
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
January, 2010	\$0.18
February, 2010	\$0.18
March, 2010	\$0.18
April 2010	\$0.21

<u>Month of Record and Payment Date</u>	<u>Amount per Trust Unit/Share</u>
May 2010	\$0.21
June 2010	\$0.21
July 2010	\$0.22
August 2010	\$0.22
September 2010	\$0.22
October 2010	\$0.22
November 2010	\$0.22
December 2010	\$0.22
January 2011	\$0.24
February 2011	\$0.24
March 2011	\$0.24

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. Transactions during the years 2010 and 2009 in the shares of the common stock of the Company are as follows:

	2010		2009	
	Number	Amount (\$ 000s)	Number	Amount (\$ 000s)
Common Shares				
Balance, beginning of year	18,619,641	121,955	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	599,900	12,378	92,600	1,898
Transfer of contributed surplus to share capital	-	697	-	103
Issue costs for private placement	-	-	-	(1,046)
Future tax effect of share issue costs	-	-	-	267
Balance, end of year	19,219,541	135,030	18,619,641	121,955

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 a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,921,954 common shares (2009 – 1,861,964). 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, 2010 and 2009, and changes during the twelve month periods ended on those dates is presented below:

	December 31, 2010		December 31, 2009	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	1,330,900	\$ 20.36	1,390,500	\$ 20.50
Options granted	36,000	36.98	33,000	14.90
Options cancelled	(20,000)	34.66	-	-
Options exercised	(599,900)	20.63	(92,600)	20.50
Outstanding at end of year	747,000	\$ 20.56	1,330,900	\$ 20.36
Options exercisable at end of year	255,500	\$ 20.50	370,900	\$ 20.50

The following table summarizes information about options outstanding at December 31, 2010:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding At 12/31/10	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at 12/31/10	Weighted-Average Exercise Price
\$14.90	22,000	2.1 years	\$14.90	-	\$ -
20.50	719,000	1.9 years	20.50	255,500	20.50
48.60	6,000	2.5 years	48.60	-	-
\$14.90-\$48.60	747,000	1.9 years	\$20.56	255,500	\$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 2010	\$34.65 to \$37.95	433,101
February 2010	\$33.30 to \$35.62	377,299
March 2010	\$33.35 to \$37.79	314,255
April 2010	\$36.58 to \$39.01	447,411
May 2010	\$31.27 to \$38.25	537,813
June 2010	\$33.00 to \$36.43	161,817
July 2010	\$33.06 to \$36.90	269,352
August 2010	\$36.44 to \$40.57	370,857
September 2010	\$38.49 to \$43.15	578,859
October 2010	\$39.68 to \$43.42	491,066
November 2010	\$41.51 to \$44.80	488,023
December 2010	\$42.00 to \$53.56	2,819,512

On December 31, 2010, the closing price of Bonterra shares on the TSX was \$51.65 (December 31, 2009 - \$34.66).

The Company as of December 31, 2010 had 19,219,541 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 as follows:

Name and Municipality of residence	Position Since	Principal Occupation for Past Five Years
Gary J. Drummond ⁽¹⁾ Nassau, Bahamas	Director August, 1999	Mr. Drummond is a private investor and a director of several entities including Geomark Exploration Ltd. and Pine Cliff Energy Ltd and a Trustee for Heating Oil Partners Income Fund.
George F. Fink Calgary, Alberta	CEO, Director and Chairman January, 1981	Bachelor of Commerce degree, Chartered Accountant. Engaged part-time as the CEO and a Chairman of the Board of Geomark Exploration Ltd., Pine Cliff Energy Ltd. and First National AlarmCap Income Fund.
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 ⁽²⁾ Vancouver, B.C.	Director January, 1981	Lawyer and Principal with the Vancouver law firm of Tupper, Jonsson & Yeadon. Also a director of Geomark Exploration Ltd., Pine Cliff Energy Ltd., Caledonia Mining Corp., Comet Industries Ltd., Astorius Resources Ltd., Acrex Ventures Ltd., Dolly Varden Resources Inc., and Alita Resources Ltd.
Garth E. Schultz Calgary, Alberta ⁽²⁾	CFO and Secretary November, 1994	Chartered Accountant. Engaged part-time as CFO of Geomark Exploration Ltd. and Pine Cliff Energy Ltd.
Robb D. Thompson ⁽²⁾ Calgary, Alberta	Vice President, Finance February 14, 2011	Chartered Accountant, Honors Bachelor of Commerce Degree. Engaged part-time as Vice President, Finance of Geomark Exploration Ltd. and Pine Cliff Energy Ltd. Prior thereto, from February 2008 to October 2010, Chief Financial Officer of Sonde Resources Corp., a public oil and gas company. Prior thereto, from January 2007 to January 2008, Chief Financial Officer of Berkana Energy Inc., a public oil and gas company. Prior thereto, from September 2000 to December 2006, Chief Executive Officer of Dynetek Industries Ltd., a public alternative energy company.
F.W. Woodward ⁽¹⁾ Calgary, Alberta	Director January, 1981	Private investor. Mr. Woodward is a director of Geomark Exploration Ltd. and Pine Cliff Energy Ltd.

Notes:

⁽¹⁾ Member of the Audit Committee. Chaired by F.W. Woodward.

⁽²⁾ Garth E. Schultz has retired with an effective date of March 31, 2011. Robb D. Thompson will be promoted to Chief Financial Officer (CFO) effective March 31, 2011 and will succeed Garth E. Schultz as CFO and Secretary.

The 1) Compensation committee; 2) Policy, Governance and Nominating committee; 3) Disclosure committee; and 4) Reserves committee consist of all four board members.

All of the directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 4,898,333 common shares representing approximately 25.4 percent of the issued and outstanding common shares 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 Appendix "C" 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 as follows:

Name	Education and Experience
F. William Woodward (Chairman)	<ul style="list-style-type: none">• Private investor.• Director of corporations such as Bonterra Energy Corp., Geomark Exploration Ltd. 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">• LLB. 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. 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
2010	\$ 204,448	\$ 9,827	\$ -
2009	\$ 218,731	\$ -	\$ -

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 March 24, 2011, which relates to the Annual General Meeting of Unitholders to be held on May 19, 2011. 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, 2010 and 2009, which are included in Bonterra's Annual Report for the year ended December 31, 2010.

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 Lankester
 Phone: (403) 750-2554 Facsimile: (403) 265-7488
 Email: klankester@bonterraenergy.com

APPENDIX "A"

**Form 51-101F2
Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor**

Report on Reserves Data

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

1. We have evaluated the Company's Reserves Data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The Reserves Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Bonterra Energy Corp., As of December 31, 2010, prepared October 2010 to February 2011	Canada				
Total			Nil	713,611	Nil	713,611

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.
6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited Calgary, Alberta
February 03, 2011

(signed) "Eseoghene N. Omatsone"
Eseoghene N. Omatsone, P. Eng., MBA
Senior Petroleum Engineer

(signed) "Christopher S. Wilcox"
Christopher S. Wilcox, P. Eng
Petroleum Engineer

(signed) "Ian E. Ooi"
Ian E. Ooi, P. Eng
Petroleum Engineer

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

(signed) "Alec Kovaltchouk"
Alec Kovaltchouk, P. Geol.
Manager, Geoscience and Associate

(signed) "Harry J. Helwerda"
Executive Vice-President and Director

APPENDIX “B”

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

**Report of Management and Directors
On Reserves Data and Other Information**

Management of Bonterra Energy Corp. (the “Company”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

The board of directors of the Company has:

- a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator;
- b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The board of directors of the Company has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

- a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- c) the content and filing of this report.

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

(signed) “George F. Fink”
George F. Fink, Chief Executive Officer

(Signed) “Garth Schultz”
Garth Schultz, Chief Financial Officer

(Signed) “F.W. Woodward”
F. W. Woodward, Director

(Signed) “Carl R. Jonsson”
Carl R. Jonsson, Director

March 24, 2011

APPENDIX "C"

AUDIT COMMITTEE CHARTER

Purpose of the Committee

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

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

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

The Committee shall consist of at least three directors. Members of the Committee shall be appointed by the Board and may be removed by the Board in its discretion. The members of the Committee shall elect a Chairman from among their number. Each director appointed to the Committee shall be an outside director who is unrelated. An outside, unrelated director is a director who is independent of management and is free of any interest, any business or other relationship which could, or could reasonably be perceived, to materially interfere with the director's ability to act with the view to the best interests of the Company, other than interests and relationships arising from shareholding. In determining whether a director is independent of management, the Board shall make reference to the current legislation, rules, policies and instruments of applicable regulatory authorities. None of the members of the Committee may be officers or employees of the 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 overseeing. Management is responsible for preparing the Company's financial statements and other financial information and for the fair presentation of the information set forth in the financial statements in accordance with 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) Chief Executive Officer;
- (ii) President; and
- (iii) 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.