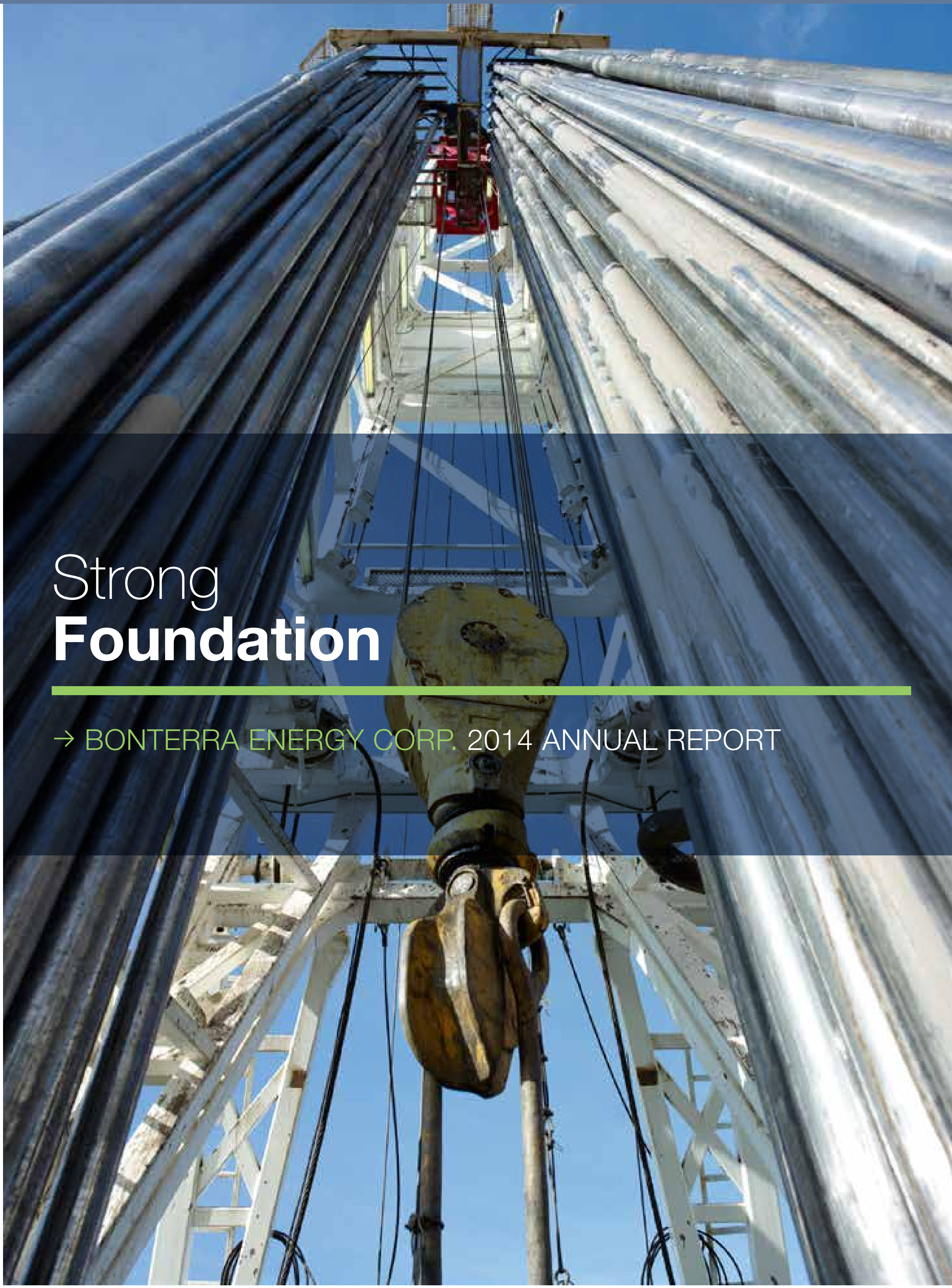


Strong **Foundation**

→ BONTERRA ENERGY CORP. 2014 ANNUAL REPORT

Strong **Foundation**

Bonterra Energy Corp. is a high-yield, dividend paying oil and gas company headquartered in Calgary, Alberta, Canada with a proven history of growing funds flow, production and reserves per share. Bonterra's prudent approach to financial management combined with a high-quality asset base and commitment to operational excellence form our sustainable model.

Contents

01 Proven and Committed Team

Experienced management

A key ingredient of Bonterra's strong foundation is our team of committed people. Led by a seasoned Board of Directors, Bonterra's dedicated and hard-working Management, staff and consultants have been instrumental in the successful execution of the Company's strategy.

02 High Quality Assets

Large oil-in-place assets offer long reserve life

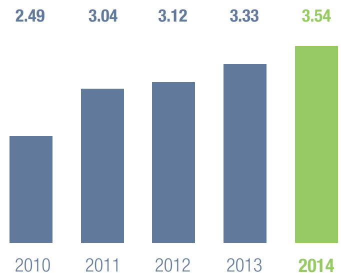
Bonterra's large and concentrated asset base is focused in the Pembina Cardium pool, which has an estimated 10.6 billion barrels of oil in place with less than 13% produced to date. As one of the largest operators in the area, Bonterra maintains a low-risk drilling inventory of over 15 years, and has access to infrastructure which supports the Company's growing production of high netback, light oil.

Bonterra is very well positioned for continued acquisition opportunities, as well as ongoing improvements in operational performance. Against the backdrop of changing commodity prices, Bonterra will prudently allocate capital to those opportunities that offer the best results with the highest economic returns.

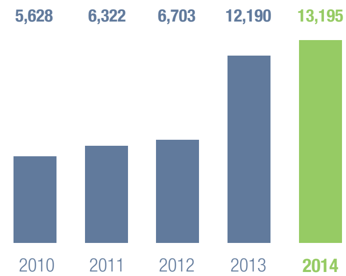
10.6 BILLION

Barrels of oil in place estimated in the Pembina Cardium pool

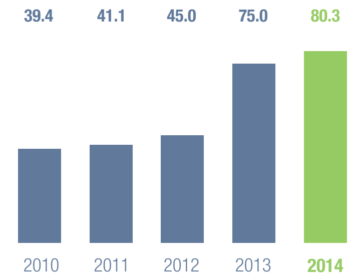
CASH DIVIDENDS/ DISTRIBUTIONS TO INVESTORS
($ per share)



PRODUCTION GROWTH
(boe per day)



P+P RESERVES GROWTH
(mmboe)



03 Conservative Approach

Disciplined financial management

Bonterra manages risk by maintaining a strong balance sheet and taking a conservative approach to financial management. During 2014, this included maintaining our net debt to funds flow ratio in the range of less than 1 to 1.5 times. With the significant erosion in commodity prices through the fourth quarter of 2014 and into 2015, this ratio started to rise. In response, we made a prudent decision to reduce our 2015 capital program plus decrease the monthly dividend amount to $0.15 per share from $0.30 per share, both of which help to preserve the strength of our balance sheet. We will continue to assess our cash outflows on an ongoing basis. Given the uncertainty in the commodity markets, we remain focused on maintaining financial flexibility while positioning Bonterra to achieve long-term, per share growth and paying out a sustainable dividend to shareholders.

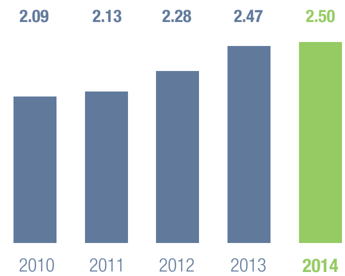
04 Evolving Operations

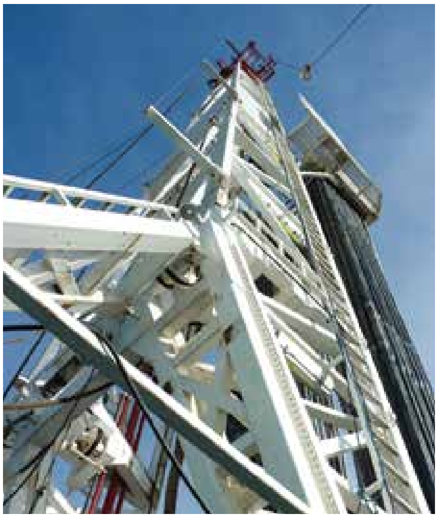
Enhancing recoveries and reducing costs

Bonterra is well positioned to achieve continued improvements in operational performance and results over the long term. With over 15 years of Cardium drilling locations in our inventory, we continue to explore increased well density within our land base in order to enhance recoveries and reduce costs. We currently anticipate that six to eight wells per section will likely become the standard for development of our Cardium assets.

Bonterra's ongoing drilling activities have successfully delineated the outer edges of our Carnwood area, where we have implemented a pad drilling program. This program involves drilling multiple horizontal wells from a single surface location, which reduces the number of drilling days and therefore costs, improves on-stream efficiencies, generates a higher rate of return and ultimately results in a smaller environmental footprint.

P+P RESERVES PER SHARE
(based on proved + probable reserves)





05 Successful Execution

Acquisitions and drilling support growth

In addition to pursuing growth through drilling and improved recoveries, Bonterra also seeks acquisition opportunities to enhance the quality of our asset base, operations and overall returns to our shareholders. In February 2015, we acquired a package of producing assets situated within Bonterra's existing Pembina Cardium lands for $172 million. The assets are complementary to our existing acreage, are accessible to our infrastructure, and provide additional inventory of long-term drilling locations. The low decline rate of approximately 7% on the acquired assets will help reduce Bonterra's corporate production declines, and along with additional operational efficiencies, will further drive attractive netbacks which support our dividend plus growth model over time.

Annual **Highlights**

As at and for the year ended ($ 000s except $ per share)		**DECEMBER 31, 2014**	December 31, 2013[1]	December 31, 2012
FINANCIAL				
Revenue – realized oil and gas sales		**339,694**	295,675	142,770
Funds flow[3]		**209,665**	181,574	80,429
Per share – basic		**6.57**	6.01	4.07
Per share – diluted		**6.54**	5.99	4.06
Payout ratio		**54%**	55%	77%
Cash flow from operations		**222,353**	173,896	74,325
Per share – basic		**6.97**	5.76	3.75
Per share – diluted		**6.94**	5.74	3.75
Payout ratio		**51%**	58%	83%
Cash dividends per share		**3.54**	3.33	3.12
Net earnings		**38,761**	62,758	33,211
Per share – basic		**1.21**	2.08	1.68
Per share – diluted		**1.21**	2.07	1.68
Capital expenditures and acquisitions, net of dispositions		**155,565**	109,227[2]	98,130
Total assets		**1,042,938**	1,000,531	419,933
Working capital deficiency		**53,642**	35,985	29,876
Long-term debt		**154,723**	156,764	166,808
Shareholders' equity		**639,006**	667,641	163,277
OPERATIONS				
Oil	– bbl per day	**8,582**	7,787	4,035
	– average price ($ per bbl)	**90.61**	89.26	82.04
NGLs	– bbl per day	**807**	744	476
	– average price ($ per bbl)	**52.26**	52.41	52.18
Natural gas	– mcf per day	**22,833**	21,954	13,157
	– average price ($ per mcf)	**4.86**	3.46	2.60
Total barrels of oil equivalent per day (boe)[4]		**13,195**	12,190	6,703

(1) Annual figures for 2013 include the results of Spartan Oil Corp. (Spartan) for the period of January 25, 2013 to December 31, 2013. Production includes 341 days for Spartan and 365 days for Bonterra.

(2) Includes the Spartan acquisition that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $121,641,000 excluding dispositions.

(3) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(4) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Quarterly **Highlights**

		2014		
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
FINANCIAL				
Revenue – realized oil and gas sales	**68,940**	88,959	99,274	82,521
Funds flow[1]	**31,926**	57,705	65,620	54,414
Per share – basic	**0.99**	1.80	2.06	1.73
Per share – diluted	**0.99**	1.79	2.04	1.72
Payout ratio	**91%**	50%	42%	50%
Cash flow from operations	**50,465**	65,705	57,089	49,094
Per share – basic	**1.57**	2.05	1.79	1.56
Per share – diluted	**1.57**	2.03	1.78	1.55
Payout ratio	**57%**	44%	49%	56%
Cash dividends per share	**0.90**	0.90	0.87	0.87
Net earnings (loss)	**(32,877)**[2]	20,983	27,614	23,041
Per share – basic	**(1.04)**	0.65	0.87	0.73
Per share – diluted	**(1.03)**	0.65	0.86	0.73
Capital expenditures and acquisitions, net of dispositions	**20,605**	41,205	39,519	54,236
Total assets	**1,042,938**	1,080,801	1,066,145	1,043,822
Working capital deficiency	**53,642**	55,047	36,399	62,488
Long-term debt	**154,723**	140,339	151,145	143,103
Shareholders' equity	**639,006**	697,337	699,284	678,224
OPERATIONS				
Oil – bbl per day	**8,762**	8,874	9,109	7,567
– average price ($ per bbl)	**71.37**	92.73	102.36	96.53
NGLs – bbl per day	**911**	818	775	721
– average price ($ per bbl)	**37.49**	54.13	53.50	67.81
Natural gas – mcf per day	**22,883**	21,981	24,163	22,307
– average price ($ per mcf)	**3.92**	4.54	4.85	6.16
Total barrels of oil equivalent per day (boe)[3]	**13,488**	13,355	13,911	12,006

(1) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(2) Net loss in the fourth quarter of 2014 is primarily due to an increase in deferred tax expense as a result of an agreement with CRA.

(3) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

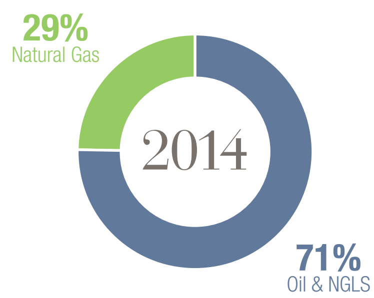
Report to **Shareholders**

Bonterra is pleased to report its financial and operational results for the year and to provide highlights with regard to its recent $172 million acquisition of additional properties in the Pembina Alberta oil field – the largest oil field in Canada.

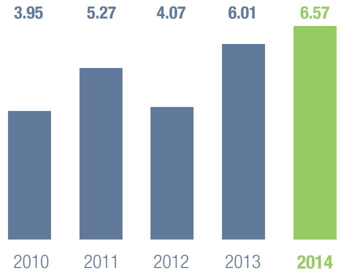
During 2014, the resource industry realized some of its best times but also some of its toughest challenges.

- The first three quarters had a crude oil realized price that averaged $97.27 per bbl and a natural gas realized price that averaged $5.17 per mcf. Bonterra's cash netback averaged $49.28 per barrel of oil equivalent (boe) over the first nine months of the year; one of the highest netbacks in the Company's history;
- Q4 was quite a contrast as the crude oil realized price averaged $73.15 per bbl and natural gas realized prices averaged $3.92 per mcf resulting in a cash netback average of $34.20 per boe; one of the lowest netbacks Bonterra has realized during the past five years;
- An agreement was negotiated with Canada Revenue Agency with regard to tax pools. The agreement resulted in a reduction in certain tax pools and an increase in deferred tax expense in Q4, but resulted in no cash outlay for the years 2009 to 2013;

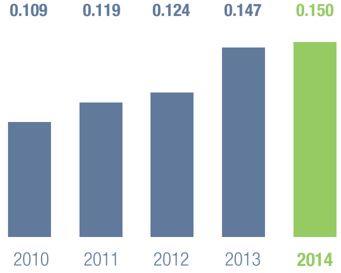
RESERVES BY COMMODITY
*based on proved plus probable reserves



FUNDS FLOW
($ per share)



PRODUCTION PER SHARE



- The Company continued to grow its production volumes and reserves on a gross basis by eight and seven percent, respectively and on a per share basis by two and 1.2 percent, respectively;
- The annual dividend paid to shareholders was increased to $3.54; an increase of 6 percent over 2013.
- Bonterra's share price opened the year on January 1, 2014 at $54.15 but fell to $42.72 by December 31, 2014 in response to the weaker commodity price environment; and
- The Company continued an active drilling program including 65 gross (47.5 net) horizontal wells with a 100 percent success rate.

2015 Acquisition

On February 19, 2015 Bonterra announced the acquisition of certain oil and gas assets from a senior oil and gas producer. The assets are mainly Cardium zone assets in the Pembina area and the production is complimentary to current Bonterra acreage. The acquisition highlights include:

- Approximately 1,800 boe per day production (based on seller's average volumes for January 2015);
- 86 percent weighted to oil and natural gas liquids; 14 percent to natural gas;
- 7 percent decline rate;
- 136 net potential undrilled horizontal well locations;
- 66 sections (38 net) gross Cardium acreage;
- $172 million purchase price prior to normal adjustments, financed mainly through bank debt; and
- April 15, 2015 scheduled closing.

This acquisition strengthens Bonterra's position as a major owner and operator in Canada's largest oil field.

Outlook

The future for Bonterra continues to be positive on a long-term basis, although in the short term low commodity prices are expected to significantly reduce funds flow. The Pembina asset acquisition has resulted in the Company temporarily taking on a higher than usual amount of debt, but this will be rectified in the future. In addition, the decrease in funds flow has resulted in a 50 percent reduction in dividend payments and a similar reduction in capital expenditures. These two items are being monitored on an ongoing basis and will be modified in the future depending on changes in production volumes and commodity prices.

The Company holds an enviable amount of light oil properties in the Cardium formation located in the Pembina and Willesden Green fields in west central Alberta. Technical advances will continue to revitalize these fields and over time should enable greater recoveries of the large resource in place. All of the companies active in the area are testing different approaches with the view to maximizing results, including assessing the optimal length of a horizontal lateral; how many wells should be drilled per section; and completion techniques including the type and size of frac to use as well as the appropriate spacing. Bonterra has many years of undrilled locations for future drilling, and as technological advances continue, the amount of oil and gas recovered is expected to increase.

A conservative approach will continue to be a key factor in Bonterra's corporate culture. Debt levels will be monitored, annual growth will be assessed and dividend increases will be cautiously monitored.

The Board of Directors wishes to thank the employees for their contribution to a very successful year and its shareholders for their continued support.

GEORGE F. FINK
Chief Executive Officer and Chairman of the Board

Strong **Foundation**

Bonterra is built on a strong foundation, comprised of a high-quality land base concentrated in the large Pembina Cardium oil pool, a conservative approach to financial management, and an experienced, committed team. Collectively, these elements support our attractive dividend-plus-growth model.

→ A SUSTAINABLE FORMULA

Attractive asset base

Bonterra's concentrated land position is situated on one of Western Canada's largest conventional oil pools, featuring very low recoveries to date. With our current development plan and the acquisition completed in early 2015, we have more than 15 years of future drilling inventory in the Cardium.

Operational excellence

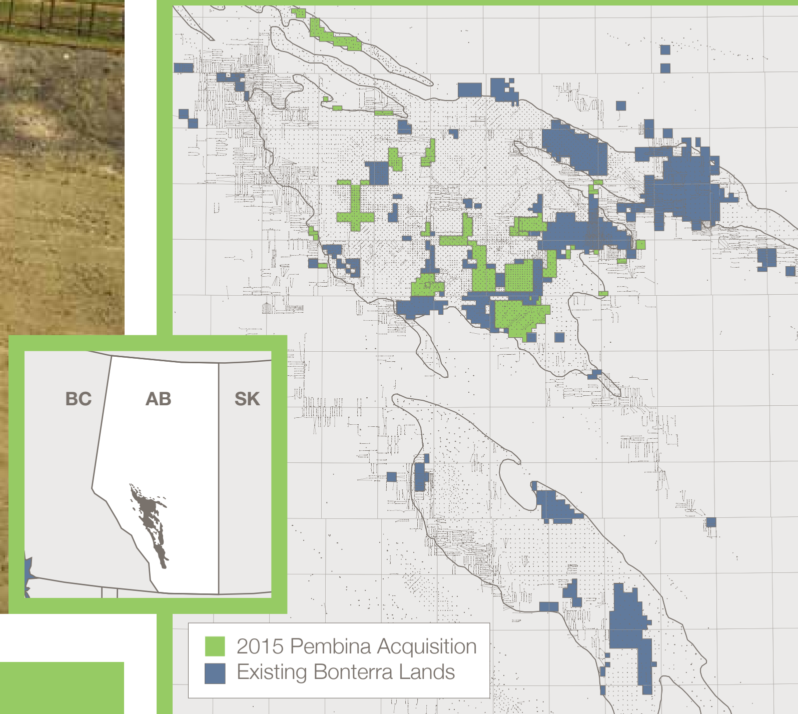
The development plan for our Cardium assets continues to evolve to maximize recoveries, minimize costs and reduce our environmental footprint. With increased well spacing density and pad drilling across our acreage, we have realized positive impacts to recoveries, reduced drilling days which also reduces costs, and improved our overall on-stream efficiencies.

Conservative balance sheet

Preserving balance sheet strength and exercising conservative financial management remain key priorities. With our careful approach, Bonterra has greater flexibility to manage funds flow, capital spending and debt levels during periods of weaker commodity prices to ensure long-term sustainability.

Responsible dividend

Since inception, Bonterra has paid a monthly dividend targeted at 50-65% of funds flow. The dividend amount can be adjusted depending on the commodity price environment and the strength of our funds flow to ensure our balance sheet remains strong. Bonterra increased the dividend in mid-2014 during a strong commodity price environment, and then reduced it to protect the balance sheet following a price collapse in early 2015.



→ EVOLVING DEVELOPMENT STRATEGY

The implementation of multi-well pad development in 2014 marked an evolution in Bonterra's pool exploitation strategy from a more conventional approach to a development plan typically used in resource plays. Pad drilling helps lower capital costs because there is less movement of equipment and reduced drilling times, and it contributes to lower fixed operating costs on a per boe basis such as property taxes, labour and other lease operating costs. During periods of weaker commodity prices and market uncertainty, we will allocate capital to projects where attractive rates of return are still achievable, such as workovers and recompletions to add low-cost barrels, while continuing to seek efficiency improvements across our overall asset base.

→ DRILLING ADVANCEMENTS

Bonterra continues to seek ways to add incremental production from our assets, including through the implementation of a water flood program in Carnwood, as well as increasing drilling spacing to expand our inventory of future well locations. Bonterra has over 15 years of drilling opportunities, not including any targets in the Belly River or other deeper zones in the Pembina field, nor any potential from our Saskatchewan or British Columbia lands. In addition, we fully transitioned to cased-hole versus open-hole packers for our completions in 2014 which allows for pinpointed frac placement. As a result of the advances in completion technology coupled with horizontal, multi-well pad drilling, our capital efficiencies have improved.

2014

13,195 BOE PER DAY AVERAGE ANNUAL PRODUCTION

Exceeded forecasted guidance of 12,400 to 12,700 boe per day

71% OIL AND LIQUIDS WEIGHTED PRODUCTION

Light oil drives attractive netbacks

43 GROSS (42.6 NET) OPERATED & 22 GROSS (4.9 NET) NON-OPERATED

Horizontal wells drilled in 2014 with 100% success rate

Statistical **Review**

→ CORPORATE RESERVES INFORMATION

Bonterra engaged the services of Sproule Associates Limited to prepare a reserves evaluation with an effective date of December 31, 2014. The reserves are located in the provinces of Alberta, British Columbia and Saskatchewan. The gross reserve figures from the following tables represent Bonterra's ownership interest before royalties and before consideration of the Company's royalty interests. Tables may not add due to rounding.

Summary of Gross Oil and Gas Reserves as of December 31, 2014

Reserve Category:	Light and Medium Oil (mbbl)	Natural Gas (mmcf)	Natural Gas Liquids (mbbl)	Boe[1] (mboe)
PROVED				
Developed Producing	21,263	54,190	2,023	32,317
Developed Non-Producing	796	1,432	63	1,098
Undeveloped	18,471	52,506	2,158	29,380
TOTAL PROVED	40,529	108,128	4,245	62,795
PROBABLE	11,190	30,759	1,136	17,453
TOTAL PROVED PLUS PROBABLE	51,719	138,887	5,381	80,248

Reconciliation of Company Gross Reserves by Principal Product Type as of December 31, 2014

	Light and Medium Oil and Natural Gas Liquids		Natural Gas		Boe[1]	
	Proved (mbbl)	Proved plus Probable (mbbl)	Proved (mmcf)	Proved plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2013	40,251	55,616	83,070	116,190	54,096	74,980
Extension	1,547	1,917	17,829	22,378	4,519	5,647
Improved Recovery	6,281	7,992	7,320	9,371	7,501	9,554
Infills	-	-	-	-	-	-
Technical Revisions	153	(5,006)	8,535	(455)	1,575	(5,082)
Discoveries	-	-	-	-	-	-
Acquisitions	32	40	111	138	51	63
Dispositions	-	-	-	-	-	-
Economic Factors	(64)	(31)	(403)	(401)	(131)	(98)
Production	(3,427)	(3,427)	(8,334)	(8,334)	(4,816)	(4,816)
DECEMBER 31, 2014	**44,774**	**57,101**	**108,128**	**138,887**	**62,795**	**80,248**

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Summary of Net Present Values of Future Net Revenue as of December 31, 2014

($000's)	Net Present Value Before Income Taxes Discounted at (% per Year)		
Reserve Category:	0%	5%	10%
PROVED			
Developed Producing	1,306,489	892,760	684,204
Developed Non-Producing	49,521	30,494	22,071
Undeveloped	956,643	515,200	304,571
TOTAL PROVED	2,312,653	1,438,454	1,010,846
PROBABLE	913,471	467,586	301,792
TOTAL PROVED PLUS PROBABLE	3,226,124	1,906,040	1,312,638

Finding, Development and Acquisition (FD&A) Costs

The Company has historically been active in its capital development program. Over three years, Bonterra has incurred the following FD&A[(3)] costs excluding Future Development Costs:

	2014 FD&A Costs per boe[(1)(2)(3)]	2013 FD&A Costs per boe[(1)(2)(3)]	2012 FD&A Costs per boe[(1)(2)(3)]	Three Year Average[(4)]
Proved Reserve Net Additions	$11.60	$23.63	$13.64	$18.52
Proved plus Probable Reserve Net Additions	$15.54	$20.12	$16.05	$18.71

Over three years, Bonterra has incurred the following FD&A(3) costs including Future Development Costs:

	2014 FD&A Costs per boe[(1)(2)(3)]	2013 FD&A Costs per boe[(1)(2)(3)]	2012 FD&A Costs per boe[(1)(2)(3)]	Three Year Average[(4)]
Proved Reserve Net Additions	$18.93	$24.80	$20.91	$22.47
Proved plus Probable Reserve Net Additions	$22.67	$21.06	$21.62	$21.45

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(3) FD&A costs are net of proceeds of disposition and the FD&A costs per boe are based on reserves acquired net of reserves disposed of.

(4) Three year average is calculated using three year total capital costs and reserve additions on both a Proved and Proved plus Probable reserves on a weighted average basis.

Commodity Prices Used in the Above Calculations of Reserves are as Follows:

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 (% per Yr)	Exchange Rate ($US/$Cdn)
FORECAST						
2015	70.35	3.32	50.34	78.60	1.5	0.8500
2016	87.36	3.71	62.51	97.60	1.5	0.8700
2017	98.28	3.90	70.32	109.80	1.5	0.8700
2018	99.75	4.47	71.37	111.44	1.5	0.8700
2019	101.25	5.05	72.44	113.12	1.5	0.8700
2020	103.85	5.13	74.31	116.02	1.5	0.8700

Production

	2014		
	OILS AND NGLS (BBL PER DAY)	**NATURAL GAS (MCF PER DAY)**	**TOTAL (BOE PER DAY)**
Alberta	**9,206**	**21,107**	**12,723**
Saskatchewan	**169**	**41**	**176**
British Columbia	**15**	**1,685**	**296**
	9,390	**22,833**	**13,195**

Land Holdings

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

	2014		2013	
	GROSS ACRES	**NET ACRES**	Gross Acres	Net Acres
Alberta	**245,263**	**150,835**	230,885	149,466
Saskatchewan	**9,576**	**6,509**	38,750	36,525
British Columbia	**62,045**	**22,639**	62,045	22,639
	316,884	**179,983**	331,680	208,630

Petroleum and Natural Gas Expenditures

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)	**2014**	2013
Land	**402**	36
Acquisitions	**-**	(10,000)
Dispositions	**(1,152)**	(2,414)
Exploration and development costs	**156,315**	121,605
Net petroleum and natural gas capital expenditures	**155,565**	109,227

Drilling History

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

	2014					
	DEVELOPMENT		**EXPLORATORY**		**TOTAL**	
	GROSS	**NET**	**GROSS**	**NET**	**GROSS**	**NET**
Crude oil	**65.0**	**47.5**	**-**	**-**	**65.0**	**47.5**
Natural gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry	**-**	**-**	**-**	**-**	**-**	**-**
Total	**65.0**	**47.5**	**-**	**-**	**65.0**	**47.5**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	2013					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	55.0	35.0	-	-	55.0	35.0
Natural gas	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	55.0	35.0	-	-	55.0	35.0
Success rate	100%	100%	-	-	100%	100%

Management's **Discussion and Analysis**

The following report dated March 19, 2015 is a review of the operations and current financial position for the year ended December 31, 2014 for Bonterra Energy Corp. (Bonterra or the Company) and should be read in conjunction with the audited financial statements presented under International Financial Reporting Standards (IFRS), including the notes related thereto.

→ USE OF NON-IFRS FINANCIAL MEASURES

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio", "cash netback" and "net debt" to analyze operating performance, which are not standardized measures recognized under IFRS and do not have a standardized meaning prescribed by IFRS. These measures are commonly used in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies.

The Company calculates payout ratio as a percentage by dividing cash dividends paid to shareholders by cash flow from operating activities, both of which are measures prescribed by IFRS which appear on our statements of cash flows. We calculate cash netback by dividing various financial statement items as determined by IFRS by total production for the period on a barrel of oil equivalent basis.

→ FREQUENTLY RECURRING TERMS

Bonterra uses the following frequently recurring terms in this MD&A: "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States; "MSW Stream Index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada; "bbl" refers to barrel; "NGL" refers to Natural gas liquids; "mcf" refers to thousand cubic feet; "mmbtu" refers to million British Thermal Units; and "boe" refers to barrels of oil equivalent. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

→ NUMERICAL AMOUNTS

The reporting and the functional currency of the Company is the Canadian dollar.

→ ANNUAL COMPARISONS

As at and for the year ended ($ 000s except $ per share)		**DECEMBER 31, 2014**	December 31, 2013[1]	December 31, 2012
FINANCIAL				
Revenue – realized oil and gas sales		**339,694**	295,675	142,770
Cash flow from operations		**222,353**	173,896	74,325
Per share – basic		**6.97**	5.76	3.75
Per share – diluted		**6.94**	5.74	3.75
Payout ratio		**51%**	58%	83%
Cash dividends per share		**3.54**	3.33	3.12
Net earnings		**38,761**	62,758	33,211
Per share – basic		**1.21**	2.08	1.68
Per share – diluted		**1.21**	2.07	1.68
Capital expenditures and acquisitions, net of dispositions		**155,565**	109,227[2]	98,130[3]
Total assets		**1,042,938**	1,000,531	419,933
Working capital deficiency		**53,642**	35,895	29,876
Long-term debt		**154,723**	156,764	166,808
Shareholders' equity		**635,198**	667,641	163,277
OPERATIONS				
Oil	– bbl per day	**8,582**	7,787	4,035
	– average price ($ per bbl)	**90.61**	89.26	82.04
NGLs	– bbl per day	**807**	744	476
	– average price ($ per bbl)	**52.26**	52.41	52.18
Natural gas	– mcf per day	**22,833**	21,954	13,157
	– average price ($ per mcf)	**4.86**	3.46	2.60
Total barrels of oil equivalent per day (boe per day)		**13,195**	12,190	6,703

(1) Annual figures for 2013 include the results of Spartan Oil Corp. (Spartan), for the period of January 25, 2013 to December 31, 2013. Production includes 341 days for Spartan and 365 days for Bonterra.

(2) Includes the Spartan Transaction that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $121,641,000 excluding dispositions.

(3) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

→ QUARTERLY COMPARISONS

	2014			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
FINANCIAL				
Revenue – oil and gas sales	**68,940**	88,959	99,274	82,521
Cash flow from operations	**50,465**	65,705	57,089	49,094
Per share – basic	**1.57**	2.05	1.79	1.56
Per share – diluted	**1.57**	2.03	1.78	1.55
Payout ratio	**57%**	44%	49%	56%
Cash dividends per share	**0.90**	0.90	0.87	0.87
Net earnings (loss)	**(32,877)**	20,983	27,614	23,041
Per share – basic	**(1.04)**	0.65	0.87	0.73
Per share – diluted	**(1.03)**	0.65	0.86	0.73
Capital expenditures and acquisitions, net of dispositions	**20,605**	41,205	39,519	54,236
Total assets	**1,042,938**	1,080,801	1,066,145	1,043,822
Working capital deficiency	**53,642**	55,047	36,399	62,488
Long-term debt	**154,723**	140,339	151,145	143,103
Shareholders' equity	**635,198**	697,337	699,284	678,224
OPERATIONS				
Oil (bbl per day)	**8,762**	8,874	9,109	7,567
NGLs (bbl per day)	**911**	818	775	721
Natural gas (mcf per day)	**22,883**	21,981	24,163	22,307
Total (boe per day)	**13,488**	13,355	13,911	12,006

	2013			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1[1]
FINANCIAL				
Revenue – oil and gas sales	**70,917**	78,946	79,344	66,468
Cash flow from operations	**47,772**	43,953	41,445	40,726
Per share – basic	**1.53**	1.41	1.35	1.47
Per share – diluted	**1.52**	1.40	1.35	1.46
Payout ratio	**56%**	60%	62%	53%
Cash dividends per share	**0.85**	0.84	0.84	0.80
Net earnings	**15,254**	19,690	15,119	12,695
Per share – basic	**0.50**	0.63	0.49	0.46
Per share – diluted	**0.49**	0.63	0.49	0.46
Capital expenditures and acquisitions, net of dispositions	**25,965**	34,025	9,731	39,506[2]
Total assets	**1,000,531**	1,002,773	987,067	1,016,594
Working capital deficiency	**35,895**	43,681	26,824	31,519
Long-term debt	**156,764**	147,189	179,379	189,509
Shareholders' equity	**667,641**	671,528	648,574	658,062
OPERATIONS				
Oil (bbl per day)	**7,964**	7,310	8,414	7,459
NGLs (bbl per day)	**691**	772	782	732
Natural gas (mcf per day)	**22,802**	22,274	20,554	22,176
Total (boe per day)	**12,456**	11,794	12,621	11,887

(1) Quarterly figures for Q1 2013 include the results of Spartan Oil Corp. (Spartan), for the period of January 25, 2013 to March 31, 2013. Production includes 65 days for Spartan and 90 days for Bonterra.

(2) Includes the Spartan Transaction that closed on January 25, 2013 that included $10,000,000 of acquired cash that reduced capital expenditures from $49,506,000.

→ BUSINESS ENVIRONMENT AND SENSITIVITIES

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials. The following table depicts selective market benchmark prices and foreign exchange rates in the last eight quarters to assist in understanding volatility in prices and foreign exchange rates that have impacted Bonterra's financial and operating performance. The increases or decreases for Bonterra's realized price for oil and natural gas for each of the eight quarters is explained in detail in the following table.

	Q4-2014	Q3-2014	Q2-2014	Q1-2014	Q4-2013	Q3-2013	Q2-2013	Q1-2013
Crude oil WTI ($US per bbl)	**73.15**	97.17	102.99	98.68	97.44	105.82	94.22	94.37
WTI to MSW Stream Index Differential ($US per bbl)[1]	**(6.46)**	(7.93)	(6.14)	(8.25)	(14.93)	(4.72)	(3.67)	(6.95)
Foreign exchange $US to $Cdn	**1.1357**	1.0893	1.0905	1.1035	1.0498	1.0385	1.0234	1.0089
Bonterra average realized price ($Cdn per bbl)	**71.37**	92.73	102.36	96.53	80.88	103.30	89.38	84.20
Natural gas AECO ($Cdn per mcf)	**3.58**	4.00	4.67	5.69	3.52	2.43	3.52	3.18
Bonterra average realized price ($Cdn per mcf)	**3.92**	4.54	4.85	6.16	3.85	2.71	4.13	3.21

(1) This differential accounts for the major difference between WTI and Bonterra's average realized price (before quality adjustments and foreign exchange).

The overall volatility in Bonterra's average realized commodity pricing can be impacted by numerous events, some of which are:

- Worldwide crude oil supply and demand imbalance;
- Whether there is sufficient take-away capacity leading to increasing or decreasing oil inventory drawdowns;
- Weather dependence; the cold winter across North America has not offset the increased gas production;
- Timing of plant and refinery turnarounds;
- North American production decline management;
- Geo-political events in the middle east countries that affect worldwide crude oil production; and
- The reduced value of the Canadian dollar compared to the US dollar continues to positively affect Bonterra's realized prices.

In December 2014, WTI decreased to under $60 US per bbl and has dropped further in the first quarter of 2015 primarily due to the worldwide crude oil supply and demand imbalance partially driven by large production gains in North America. It is difficult to predict future pricing, but the Company expects crude oil prices to remain low for the remainder of 2015.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently showing the effect of the change of one variable; with all other variables being held constant.

Annualized sensitivity analysis on cash flow, as estimated for 2015[(1)]

Impact on cash flow	Change ($)	$000s	$ per share[(2)]
Realized crude oil price ($ per bbl)	1.00	2,701	0.08
Realized natural gas price ($ per mcf)	0.10	743	0.02
$US to $Cdn exchange rate	0.01	1,593	0.05

(1) This analysis uses current royalty rates, annualized estimated average production of 12,800 boe per day and no changes in working capital.

(2) Based on annualized basic weighted average shares outstanding of 32,169,623.

→ BUSINESS OVERVIEW, STRATEGY AND KEY PERFORMANCE DRIVERS

Bonterra Energy Corp. is an oil and gas company engaged in the exploration, acquisition, development and production of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan. Bonterra's primary focus is development of the Pembina Cardium lands with horizontal infill and extension drilling. Bonterra operates 85 percent of its production with an average land working interest of 77 percent. At December 31, 2014, Bonterra has a drilling inventory of approximately 750 net locations that represents over 15 years of drilling inventory.

Bonterra spent $156,000,000 on its total capital program, primarily on the drilling of 43 gross (42.6 net) operated wells and completing and tying-in 4 gross (3.9 net) wells that were drilled in 2013. Of the 43 gross operated wells drilled, the Company drilled 10 (9.9 net) wells in the fourth quarter of 2014 (Q4 2013 – 6 wells, 5.9 net), and followed its strategy to drill the wells but not complete, equip and tie-in until the beginning of the 2015 year. As well, 22 gross (4.9 net) non-operated wells were drilled and placed on production during 2014.

During 2014 Bonterra reactivated a second wholly owned gas plant which increased operated gas processing capacity by 8 mmcf per day. In addition, the Company expanded, in the Carnwood area, its largest operated battery oil treating capacity to 5,000 bbl of oil production per day. The two facility expansions are significant since all facility constraints related with the Carnwood area have now been eliminated.

The Company averaged 13,195 boe per day for the year, which exceeded its annual average production guidance of 12,400 to 12,700 boe per day, primarily due to drilling an additional four wells and higher than anticipated production from the new horizontal wells.

Due to a significant drop in commodity prices during the fourth quarter of 2014 and early 2015, Bonterra and the majority of oil and gas producing companies have drastically reduced their capital spending programs. Until the Company sees a positive prolonged shift in energy pricing, the Company anticipates reduced production volumes for 2015 due to less new production to offset natural production declines. In addition, with the current volatile pricing environment for crude oil, the Company has reduced the monthly dividend from $0.30 per share to $0.15 per share commencing with the February 2015 dividend.

On February 19, 2015, the Company entered into a purchase and sale agreement (the Asset Agreement) to acquire certain oil and gas assets (the Pembina Assets) from a senior oil and gas producer (the Acquisition). The Pembina Assets are Cardium focused in the Pembina Area of Alberta, including upper zones in the Belly River, with a production base that is complementary to current Bonterra acreage, and which provides additional inventory of long-term drilling locations. Consideration for the Pembina Assets was $172,000,000, prior to any adjustments, which will be initially financed by a combination of working capital and an increased debt facility. The purchase price allocation using the acquisition method for the Pembina Assets is incomplete as of the date of this report. The Acquisition will have an effective date of January 1, 2015 and is presently expected to close on or before April 15, 2015. Although the Asset Agreement is binding between the parties, completion of the Acquisition is subject to standard regulatory approvals. The Acquisition adds approximately 1,800 boe per day of production that is 86 percent oil and NGL weighted with a low decline rate. These Pembina Assets also include 132 net future potential drilling locations and supporting infrastructure. With the acquisition Bonterra plans to increase its capital budget from $58 million to approximately $70 million.

As a result of the decrease in the Company's capital program, partially offset by the added production from the Acquisition starting in mid-April, the Company expects its annual production guidance for 2015 to be between 12,600 to 12,900 boe per day. Due to pricing volatility at the present time, Bonterra's annual production guidance and capital budget will be continuously monitored and adjusted according to changing commodity prices.

On November 14, 2013, the Company received a proposal letter from the Canada Revenue agency (CRA) which stated its intention to challenge the tax consequences of Bonterra's reorganization from a trust to a Corporation, which occurred on November 18, 2008. On November 27, 2014, the Company reached an agreement with CRA (the Agreement) to adjust certain tax pools.

The Agreement resulted in:

- No cash outflow for the Company for the taxation years of 2009 to 2013 and reduced cash outflows for subsequent periods;
- Eliminating years of costly court proceedings;
- Allowing Management to focus full time on the operations of the Company to enhance shareholder value; and
- A current tax provision of $10,505,000 for the 2014 taxation year. The Company utilized $6,645,000 of the federal investment tax credit receivable to reduce current taxes payable to $3,860,000.

Bonterra's successful operations are dependent upon several factors, including but not limited to, the price of energy commodity products, efficiently managing capital spending, its ability to maintain desired levels of production, control over its infrastructure, its efficiency in developing and operating properties and its ability to control costs. The Company's key measures of performance with respect to these drivers include, but are not limited to: average production per day, average realized prices, and average operating costs per unit of production. Disclosure of these key performance measures can be found in the MD&A and/or previous interim or annual MD&A disclosures.

→ DRILLING

	Three months ended						Year ended			
	DECEMBER 31, 2014		September 30, 2014		December 31, 2013		**DECEMBER 31, 2014**		December 31, 2013	
	GROSS(1)	**NET(2)**	Gross(1)	Net(2)	Gross(1)	Net(2)	**GROSS(1)**	**NET(2)**	Gross(1)	Net(2)
Crude oil horizontal – operated	**10**	**9.9**	9	8.9	6	5.9	**43**	**42.6**	30	29.7
Crude oil horizontal – non-operated	**-**	**-**	13	2.5	13	2.6	**22**	**4.9**	25	5.3
Total	**10**	**9.9**	22	11.4	19	8.5	**65**	**47.5**	55	35.0
Success rate		**100%**		100%		100%		**100%**		100%

(1) "Gross" wells means the number of wells in which Bonterra has a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Bonterra's percentage of working interest.

During 2014, the Company placed four gross (3.9 net) wells on production that were drilled in the later part of 2013, drilled 43 gross (42.6 net) wells, of which 33 (32.7 net) were placed on production with the remaining 10 wells scheduled to be on production in early 2015. As well, 22 gross (4.9 net) non-operated wells were drilled and placed on production during 2014.

→ PRODUCTION

	Three months ended			Year ended	
	DECEMBER 31, 2014	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013 (1)
Crude oil (bbl per day)	**8,762**	8,874	7,964	**8,582**	7,787
NGLs (bbl per day)	**911**	818	691	**807**	744
Natural gas (mcf per day)	**22,883**	21,981	22,802	**22,833**	21,954
Average (boe per day)	**13,488**	13,355	12,456	**13,195**	12,190

(1) In 2013, average daily production included 365 days of Bonterra production and 341 days of Spartan production.

Production volumes during the 2014 year were 13,195 boe per day compared to 12,190 boe per day in 2013, an increase of 8 percent. The increase was primarily due to an increase in the number of net wells that commenced production in 2014 compared to 2013. In addition, the Company was able to drill and tie-in new production in Q2 2014, which traditionally is not done during the spring road ban period.

→ CASH NETBACK

The following table illustrates the calculation of the Company's cash netback from operations for the periods ended:

	Three months ended			Year ended	
$ per boe	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Production volumes (boe)	**1,240,864**	1,228,681	1,145,918	**4,816,030**	4,449,280
Gross production revenue	**$ 55.56**	$ 72.40	$ 61.89	**$ 70.53**	$ 66.45
Royalties	**(5.87)**	(7.90)	(7.97)	**(7.91)**	(8.52)
Field operating costs	**(12.50)**	(15.17)	(12.11)	**(13.89)**	(12.77)
Field netback	**$ 37.19**	$ 49.33	$ 41.81	**$ 48.73**	$ 45.16
General and administrative	**(1.83)**	(2.12)	(1.85)	**(2.22)**	(2.35)
Interest and other	**(1.16)**	(1.14)	(2.12)	**(1.12)**	(2.23)
Cash netback	**$ 34.20**	$ 46.07	$ 37.84	**$ 45.39**	$ 40.58

Cash netbacks have increased for 2014 compared to 2013 primarily due to higher production volumes and prices, which were partially offset by higher operating costs. Quarter over quarter cash netbacks decreased due to lower commodity prices primarily in December which were partially offset by lower field operating costs.

→ OIL AND GAS SALES

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Revenue – oil and gas sales	**68,940**	88,959	70,917	**339,694**	295,675
Average Realized Prices ($):					
Crude oil (per bbl)	**71.37**	92.73	80.88	**90.61**	89.26
NGLs (per bbl)	**37.49**	54.13	56.48	**52.26**	52.41
Natural gas (per mcf)	**3.92**	4.54	3.85	**4.86**	3.46
Average (per boe)	**55.56**	72.40	61.89	**70.53**	68.04

Revenue from oil and gas sales increased by $44,019,000 or 15 percent compared to 2013. This increase was due to higher production volumes and commodity prices.

The quarter over quarter decrease in oil and gas revenues of 23 percent or $20,019,000 was due to decreased oil prices of approximately 42 percent in December.

The Company's product split on a revenue basis for 2014 is approximately 84 percent weighted towards crude oil and NGLs. This ratio will likely remain similar in 2015.

→ ROYALTIES

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Crown royalties	**5,021**	6,045	4,546	**23,779**	18,031
Freehold, gross overriding and other royalties	**2,259**	3,662	4,583	**14,331**	19,867
Total royalties	**7,280**	9,707	9,129	**38,110**	37,898
Crown royalties – percentage of revenue	**7.3**	6.8	6.4	**7.0**	6.1
Freehold, gross overriding and other royalties – percentage of revenue	**3.3**	4.1	6.5	**4.2**	6.7
Royalties – percentage of revenue	**10.6**	10.9	12.9	**11.2**	12.8
Royalties $ per boe	**5.87**	7.90	7.97	**7.91**	8.52

Royalties paid by the Company consist of crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. The Company's average crown royalty rate is approximately seven percent for 2014 compared to 6.1 percent for 2013. The crown royalty rate increase was primarily due to increased ratio of crown wells in the Carnwood area and additional crown wells that have reached accumulated production thresholds and are no longer eligible for the initial five percent crown royalty rate. Increased production volumes, along with the higher crown oil reference prices are also responsible for the increased crown royalty rates. Quarter over quarter increase in crown royalties as a percentage of revenue, is primarily due to the Alberta Crown forecasted reference prices used for oil, which trail actual Edmonton Par prices, compared to the crude oil price Bonterra received in the fourth quarter.

Non-crown royalties decreased for the 2014 year compared to the same period in 2013, primarily due to the Company drilling the majority of its new wells on crown lands compared to freehold lands.

→ PRODUCTION COSTS

	Three months ended			Year ended	
($ 000s except $ per boe)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Production costs (recurring)	**15,516**	18,643	13,877	**65,778**	56,810
Production costs (non-recurring)(1)	**-**	-	-	**1,100**	-
Total production costs	**15,516**	18,643	13,877	**66,878**	56,810
$ per boe (recurring)	**12.50**	15.17	12.11	**13.66**	12.77
$ per boe (total)	**12.50**	15.17	12.11	**13.89**	12.77

(1) Non-recurring production costs relate primarily to a one-time freehold mineral tax re-assessment in the Keystone area.

Production costs (recurring) on a per boe basis for 2014 increased seven percent from the comparable period in 2013. The increase in production costs on a per boe basis can be attributed to increased costs for oil trucking, water hauling, chemical usage and a higher number of well work overs and repairs that occurred primarily in the third quarter.

Water production (primarily load fluid recovery from frac operations) associated with new horizontal wells in a previously water flooded area in Carnwood has increased in excess of the available water injection facility capacity. The Company is addressing this issue by reactivating old vertical injectors and by commissioning two horizontal water flood pilots. One pilot injector was commissioned in the middle of August with a second injector scheduled to start injection in the first quarter of 2015. Chemical usage associated with de-emulsifiers and wax inhibitors has increased substantially in the Carnwood area due to higher production levels. In the Carnwood area, the Company has installed a new treater and is evaluating alternative programs for inhibiting wax to reduce costs. The Company also experienced higher than average well work overs primarily in the Keystone Area. The Company expects the cyclic wear and tear associated with the artificial lift system of the Keystone wells will decrease due to natural production declines and therefore decrease the frequency of well work overs in this area in the future.

Quarter over quarter the production costs decreased as the Company completed its well work overs, facility maintenance, plant turnarounds and equalization that generally occur in the third quarter.

→ OTHER INCOME

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Investment income	**12**	11	18	**56**	104
Administrative income	**22**	54	117	**282**	161
Gain on sale of properties	**-**	-	-	**671**	217
Realized gain on investments	**-**	933	-	**1,102**	278
	34	998	135	**2,111**	760

In January 2014, the Company sold a portion of its undeveloped land in the Willesden Green area for cash proceeds of $1,000,000. At the time of disposition, the Company had a carrying value of $419,000 for exploration and evaluation expenditures, resulting in a gain on sale of $581,000.

The market value of the investments held by the Company is $7,966,000 at December 31, 2014 (December 31, 2013 – $6,804,000). The increase in carrying value is mainly due to investments purchased by the Company in the fourth quarter which is offset by a decrease in the market value of investments previously held by the Company. During the year the company sold investments for proceeds of $1,539,000, resulting in a gain on sale of $1,102,000.

The Company receives administrative income by way of management fees from related parties (see related party transactions).

→ GENERAL AND ADMINISTRATION (G&A) EXPENSE

	Three months ended			Year ended	
($ 000s except $ per boe)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Employee compensation expense	**1,399**	1,805	1,403	**7,111**	5,986
Office and administration expense (recurring)	**877**	795	719	**3,559**	3,125
	2,276	2,600	2,122	**10,670**	9,111
Office and administration expense (non-recurring)(1)	**-**	-	-	**-**	1,331
Total G&A expense	**2,276**	2,600	2,122	**10,670**	10,442
$ per boe (recurring)	**1.83**	2.12	1.85	**2.22**	2.05
$ per boe (total)	**1.83**	2.12	1.85	**2.22**	2.35

(1) Non-recurring office and administration costs relates to the acquisition of Spartan.

The increase in employee compensation expense of $1,125,000 for 2014 compared to 2013 is primarily due to an increase in staff because of growing operations and accrued bonuses that resulted from higher net earnings before income taxes. Quarter over quarter decrease is primarily due to a decrease in accrued bonuses that resulted from lower net earnings before income taxes primarily as a result of reduced commodity prices. The Company has a bonus plan in which the bonus pool consists of a range between 2.5 percent to 3.5 percent of earnings before income taxes. The Company firmly believes that tying employee compensation (including the use of stock options) to the performance of the Company clearly aligns the interest of the employees with that of the shareholders.

The increase in recurring office and administration expense for 2014 compared to 2013 related to increased computer software costs, professional fees and general office expenditures. The increase quarter over quarter relates primarily to an increase in professional fees and a reduction in the allowance for doubtful accounts.

→ FINANCE COSTS

	Three months ended			Year ended	
($ 000s except $ per boe)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Interest on long-term debt	**1,220**	965	1,332	**4,282**	6,165
Other interest	**251**	498	261	**1,461**	958
Interest expense	**1,471**	1,463	1,593	**5,743**	7,123
$ per boe	**1.19**	1.19	1.39	**1.19**	1.60
Unwinding of the discounted value of decommissioning liabilities	**388**	380	284	**1,361**	1,088
Total finance costs	**1,859**	1,843	1,877	**7,104**	8,211

Interest on long-term debt decreased $1,883,000 in 2014 compared to the same period in 2013 as the Company reduced the bank debt outstanding by $24,656,000 since the end of the second quarter of 2013. The decrease in bank debt was due to increased cash flow, an equity issue in the third quarter of 2013, an increase in a subordinated promissory note and stock option proceeds received in the first half of 2014. The Company also experienced lower interest rates on its credit facilities in 2014 due to a lower net debt to cash flow ratio. Interest rates are determined by net debt to cash flow ratio on a trailing quarterly basis.

Other interest relates to amounts paid to related party (see related party transactions) and a $40,000,000 subordinated promissory note from a private investor.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $1,250,000.

→ SHARE-BASED PAYMENTS

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
	947	838	773	**2,725**	4,155

Share-based payments are a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

Share-based payments decreased by $1,430,000 from a year ago due to 1,350,500 options issued prior to Q1 2013 that were fully amortized prior to Q1 2014. In 2014 the Company granted most of its options in the second and third quarter.

Based on current outstanding options, the Company anticipates that an expense of approximately $2,317,000 will be recorded for 2015, $598,000 for 2016, and $98,000 for 2017. For more information about options issued and outstanding, refer to Note 14 of the December 31, 2014 audited annual financial statements.

→ DEPLETION AND DEPRECIATION, EXPLORATION AND EVALUATION AND GOODWILL

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Depletion and depreciation	**26,975**	28,119	24,707	**106,697**	91,779
Exploration and evaluation	**-**	-	489	**28**	1,156

Provision for depletion and depreciation increased by $14,918,000 for 2014 compared to 2013. The increase in depletion and depreciation was mainly the result of higher production volumes and increased property, plant and equipment costs. Quarter over quarter the provision for depletion and depreciation decreased primarily due to a decrease in decommissioning estimates.

Exploration and evaluation expense related to expired leases.

There were no impairment provisions recorded for the years ended December 31, 2014 and 2013.

→ TAXES

The Company recorded a current tax expense of $10,505,000 (2013 – $Nil) and a deferred tax expense of $60,327,000 for 2014 (2013 – $22,024,000) for a total tax expense of $70,832,000 (2013 – $22,024,000). The tax expense increase for 2014 compared to 2013 is related to a reduction in the Company's tax assets as a result of the Agreement with CRA and an increase in net earnings. The reduction in tax assets was charged to deferred tax expense in the statement of comprehensive income. The Company also utilized $6,645,000 of the federal investment tax credit receivable to reduce current taxes payable to $3,860,000.

For additional information regarding income taxes, see Note 13 of the December 31, 2014 annual audited financial statements.

→ NET EARNINGS (LOSS)

	Three months ended			Year ended	
($ 000s except $ per share)	**DECEMBER 31, 2014**	September 30, 2014	December 31, 2013	**DECEMBER 31, 2014**	December 31, 2013
Net earnings (loss)	**(32,877)**	20,983	15,254	**38,761**	62,758
$ per share – basic	**(1.04)**	0.65	0.50	**1.21**	2.08
$ per share – diluted	**(1.03)**	0.65	0.49	**1.21**	2.07

Net earnings in 2014 decreased by $23,997,00 compared to 2013. Decreased net earnings resulted primarily from increased tax expense from the CRA Agreement in the fourth quarter, increased depletion and depreciation and increased production costs, which was partially offset by an increase in oil and gas sales.

The quarter over quarter decrease in net earnings was mainly due to the increase in tax expense and a decrease in crude oil prices, which were partially offset by a decrease in production costs.

→ OTHER COMPREHENSIVE INCOME

Other comprehensive income for 2014 consists of an unrealized gain before tax on investments (including investment in a related party) of $1,174,000 relating to an increase in the investments' fair value (December 31, 2013 – unrealized gain of $2,725,000). The Company also disposed of a portion of these investments in 2014 for a realized gain before tax of $1,102,000 (December 31, 2013 – $278,000). Realized gains decrease other comprehensive income as these gains are transferred to net earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments including the investment in related party, net of tax.

→ CASH FLOW FROM OPERATIONS

($ 000s except $ per share)	Three months ended DECEMBER 31, 2014	Three months ended September 30, 2014	Three months ended December 31, 2013	Year ended DECEMBER 31, 2014	Year ended December 31, 2013
Cash flow from operations	**50,465**	65,705	47,772	**222,353**	173,896
$ per share – basic	**1.57**	2.05	1.53	**6.97**	5.76
$ per share – diluted	**1.57**	2.03	1.52	**6.94**	5.74

In 2014, cash flow from operations increased by $48,457,000 compared to the same period a year ago. This was primarily due to an increase in oil and gas sales and production and an increase in non-cash working capital, which were partially offset by an increase in production costs. The quarter over quarter decrease of $15,240,000 was primarily due to a decrease in crude oil prices, which was partially offset by an increase in non-cash working capital and decreased production costs.

→ RELATED PARTY TRANSACTIONS

Bonterra holds 1,034,523 (December 31, 2013 – 1,034,523) common shares in Pine Cliff which represents less than one percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares have a fair market value as of December 31, 2014 of $1,738,000 (December 31, 2013 – $1,076,000). Pine Cliff paid a management fee to the Company of $60,000 (December 31, 2013 – $60,000) plus the reimbursement of certain administrative costs. Services provided by the Company include executive services, oil and gas administration and office administration. All services performed are charged at estimated fair value. As at December 31, 2014, the Company had an account receivable from Pine Cliff of $316,000 (December 31, 2013 – $217,000).

As at December 31, 2014, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2013 – $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan for 2014 was $285,000 (December 31, 2013 – $285,000). This loan results in a substantial benefit to Bonterra as the interest paid to the CEO by Bonterra is lower than bank interest.

→ LIQUIDITY AND CAPITAL RESOURCES

Net Debt to Cash Flow

Bonterra continues to focus on managing its cash flow, capital expenditures and dividend payments. The Company continues to meet its annual guidance range of 1 to 1 times to 1.5 to 1 times net debt to a 12 month trailing cash flow ratio with a ratio of 0.9 to 1 times. The Company anticipates that with its low net debt to cash flow ratio and continued successful drilling program, it will allow the Company to sustain future after tax cash flows that will be sufficient to finance future capital expenditures and dividend payments while still operating within its guidance of debt to cash flow ratio. With the current oil commodity price environment the Company will be assessing its net debt to cash flow guidance for 2015 on a continuous basis. Due to current prices the Company has significantly reduced planned capital expenditures for 2015 compared to 2014 and has reduced the dividend payments by 50 percent on a monthly basis.

Working Capital Deficiency

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Working capital deficiency	**53,642**	35,895
Long-term bank debt	**154,723**	156,764
Net debt	**208,365**	192,659
Shareholders' equity	**635,198**	667,641
Total	**843,563**	860,300

Net Debt and Working Capital

Net debt is a combination of long-term bank debt and working capital. Net debt increased compared to the same period in 2013. This was primarily attributable to the Company's increased capital spending and dividends paid to shareholders offset partially by increased cash flow from increased production and higher field netbacks, stock option proceeds and an equity raise in the third quarter of 2013. In July 2014, the Company raised the monthly dividend from $0.29 per share to $0.30 per share. Subsequently to December 31, 2014, in order to maintain its financial strength and long-term objectives during this period of extreme market volatility, the Company reduced the monthly dividend from $0.30 per share to $0.15 per share commencing with the February 2015 dividend.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and sale of non-core assets and investments.

Effective January 17, 2014, the Company increased its Subordinated Promissory Note by an additional $15,000,000, for a total of $40,000,000 under the same terms and conditions. See Note 10 of the December 31, 2014 audited annual financial statements.

The Company has not currently entered into any financial derivative contracts.

Capital Expenditures

During the year ended December 31, 2014, the Company incurred capital costs of $155,566,000 (December 31, 2013 – $119,227,000) net of proceeds on dispositions of property, plant and equipment. The costs relate primarily to the drilling of 43 gross (42.6 net) Cardium operated horizontal wells and 22 (4.9 net) non-operated wells, a wholly owned gas plant reactivation, and upgrading facilities and gathering systems.

Long-Term Debt

Long-term debt represents the outstanding draws from the Company's credit facilities as described in the notes to the Company's condensed financial statements. As of December 31, 2014, the Company has bank facilities consisting of a $220,000,000 (December 31, 2013 – $220,000,000) syndicated revolving credit facility and a $30,000,000 (December 31, 2013 – $30,000,000) non-syndicated revolving credit facility. Amounts drawn under these facilities at December 31, 2014 totaled $154,723,000 (December 31, 2013 – $156,764,000). The interest rates on the outstanding debt as of December 31, 2014 were 3.8 percent and 3.0 percent on the Company's Canadian prime rate loan and Banker's Acceptances, respectively. The loan is revolving to April 30, 2015 and with a maturity date of April 30, 2016 and is subject to annual review. The revolving credit facilities have no fixed terms of repayment.

Advances drawn under the credit facilities are secured by a fixed and floating charge debenture over the assets of the Company. In the event the credit facilities are not extended or renewed, amounts drawn under the facility would be due and payable on the maturity date. The size of the committed credit facilities is based primarily on the value of the Company's producing petroleum and natural gas assets and related tangible assets as determined by the lenders. For more information see Note 11 of the December 31, 2014 audited annual financial statements.

Shareholders' Equity

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

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.

	DECEMBER 31, 2014		December 31, 2013	
Issued and fully paid – common shares	**NUMBER**	**AMOUNT ($ 000S)**	Number	Amount ($ 000s)
Balance, beginning of year	**31,322,171**	**685,898**	19,909,541	149,877
Acquisition	**-**	**-**	10,711,405	502,258
Share issuance	**-**	**-**	553,725	27,603
Share issue costs, net of tax		**-**		(996)
Issued pursuant to the Company's share option plan	**829,452**	**37,911**	147,500	6,625
Transfer from contributed surplus to share capital		**4,021**		531
Shares issued for oil and gas properties	**18,000**	**1,104**	-	-
Balance, end of year	**32,169,623**	**728,934**	31,322,171	685,898

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 3,216,962 (December 31, 2013 – 3,132,217) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years. For additional information regarding options outstanding, see Note 14 of the December 31, 2014 audited annual financial statements.

As of May 22, 2014, employees may elect to have the Company settle any or all options vested and exercisable using the cashless equity-settled exercise method. In connection with any such exercise, such employee shall be entitled to receive, without any cash payment (other than the taxes required to be paid in connection with the exercise), whole shares of the Company. The number of shares under option multiplied by the difference of the fair value at the time of exercise less the option exercise price, divided by the fair value at the time of exercise determines the number of whole shares issued.

→ DIVIDEND POLICY

For the year ended December 31, 2014, Bonterra paid dividends of $113,007,000 ($3.54 per share) compared to $100,180,000 ($3.33 per share) in 2013. Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, funds from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide to its shareholders a combination of sustainable growth and meaningful dividend income.

Bonterra's dividends to its shareholders are funded by cash flow from operating activities with the remaining cash flow directed towards capital spending and, where applicable, the repayment of debt. To the extent that the excess cash flow from operations after dividends is not sufficient to cover capital spending, the shortfall is funded by funds from the exercising of employee stock options, the sale of investments and by drawdowns from Bonterra's credit facilities. Bonterra intends to provide dividends to shareholders that are sustainable to the Company considering its liquidity and its long-term operational strategy. In addition, since the level of dividends is highly dependent upon cash flow generated from operations, which fluctuates significantly in relation to changes in financial and operational performance, commodity prices, interest and exchange rates and many other factors, future dividends cannot be assured. Bonterra's payout ratio based on cash flow from operations was 51 percent for the year ended December 31, 2014 (58 percent for the year ended December 31, 2013).

→ QUARTERLY FINANCIAL INFORMATION

For the periods ended ($ 000s except $ per share)	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Revenue – oil and gas sales	**68,940**	88,959	99,274	82,521
Cash flow from operations	**50,465**	65,705	57,089	49,094
Net earnings (loss)	**(32,877)**	20,983	27,614	23,041
Per share – basic	**(1.04)**	0.65	0.87	0.73
Per share – diluted	**(1.03)**	0.65	0.86	0.73

For the periods ended ($ 000s except $ per share)	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Revenue – oil and gas sales	70,917	78,946	79,344	66,468
Cash flow from operations	47,772	43,953	41,445	40,726
Net earnings	15,254	19,690	15,119	12,695
Per share – basic	0.50	0.63	0.49	0.46
Per share – diluted	0.49	0.63	0.49	0.46

The fluctuations in the Company's revenue and net earnings from quarter to quarter are primarily caused by variations in production volumes, realized oil and natural gas pricing, the related impact on royalties and production costs. Q4 2014 net earnings were lower than the prior quarters due to the Company's tax agreement with CRA.

→ CRITICAL ACCOUNTING ESTIMATES

There have been no changes to the Company's critical accounting policies and estimates as of the period ended in the financial statements.

→ FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

→ DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure the information required to be disclosed by the Company is accumulated and communicated to the Company's Management, as appropriate, to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), together with management, have concluded, based on their evaluation as of December 31, 2014 that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company. It should be noted that while the Company's CEO and CFO believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

→ INTERNAL CONTROL UPDATE

The Company's CEO and CFO are responsible for establishing and maintaining Disclosure Controls and Procedures (DC&P) and adequate Internal Control over Financial Reporting (ICFR) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements at December 31, 2014 for external purposes in accordance with International Financial Reporting Standards. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 1992). The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at the financial period end of the Company and concluded that the Company's internal control over financial reporting are effective for the foregoing purpose.

No changes were made to the Company's internal controls over financial reporting during the year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

The Company is in the process of reviewing its ICFR to be compliant with the COSO 2013 framework by December 31, 2015.

All internal control systems, no matter how well designed, have inherent limitations. These systems, therefore, provide reasonable but not absolute assurance that financial information is accurate and complete.

→ FINANCIAL REPORTING UPDATE

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements are as follows:

IAS 32 "Financial Instruments: Presentation"

Has been amended to clarify certain criteria required to be achieved in order to permit the offsetting of financial assets and financial liabilities. The retrospective adoption of the amendment does not have any impact on Bonterra's financial statements.

IAS 36 "Impairment of Assets"

Has been amended to reduce the circumstances in which the recoverable amount of cash generating units "CGUs" is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in a period. The retrospective adoption of these amendments will only impact Bonterra's disclosures in the financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 39 "Financial Instruments: Recognition and Measurement"

Has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendments does not have any impact on Bonterra's financial statements.

IFRIC 21 "Levies"

Was developed by the IFRS Interpretations Committee (IFRIC) and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this interpretation does not have any impact on Bonterra's financial statements.

→ FUTURE ACCOUNTING PRONOUNCEMENTS

In May 2014, the International Accounting Standards Board (IASB) issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. This standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. The Company has not yet assessed the impact, if any, that the new standard will have on its financial statements or whether to early adopt this new standard.

In July 2014, the IASB has amended IFRS 9 "Financial Instruments," which amends its classification and measurement of financial assets and introduces a new expected loss impairment model. This standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted and shall be applied retrospectively. The Company has not yet assessed the impact, if any, that the new amended standard will have on its financial statements or whether to early adopt this new requirement.

Additional information relating to the Company may be found on www.sedar.com or visit our website at www.bonterraenergy.com.

Management's **Responsibility for Financial Statements**

The information provided in this report, including the financial statements, is the responsibility of management. The timely preparation of the financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

GEORGE F. FINK
Chief Executive Officer and
Chairman of the Board

March 19, 2015

ROBB D. THOMPSON
Chief Financial Officer

March 19, 2015

Independent **Auditor's Report**

→ TO THE SHAREHOLDERS OF BONTERRA ENERGY CORP.

We have audited the accompanying financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statement of financial position as at December 31, 2014 and 2013, and the statement of comprehensive income, statement of cash flows and statement of changes in equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Bonterra Energy Corp. as at December 31, 2014 and 2013, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

CHARTERED ACCOUNTANTS

March 19, 2015

Calgary, Canada

Financial **Statements**

→ STATEMENT OF FINANCIAL POSITION

As at ($ 000s)	Note	DECEMBER 31, 2014	December 31, 2013
ASSETS			
CURRENT			
Accounts receivable		**20,314**	27,247
Crude oil inventory		**1,227**	749
Prepaid expenses		**2,428**	1,642
Investments		**6,228**	5,728
		30,197	35,366
Investment in related party	5	**1,738**	1,076
Exploration and evaluation assets	6	**7,629**	7,674
Property, plant and equipment	7	**901,991**	835,935
Investment tax credit receivable	13	**8,573**	27,670
Goodwill	18	**92,810**	92,810
		1,042,938	1,000,531
LIABILITIES			
CURRENT			
Accounts payable and accrued liabilities	8	**31,839**	34,261
Due to related party	9	**12,000**	12,000
Subordinated promissory note	10	**40,000**	25,000
		83,839	71,261
Bank debt	11	**154,723**	156,764
Decommissioning liabilities	12	**53,792**	37,362
Deferred tax liability	13	**115,386**	67,503
		407,740	332,890
COMMITMENTS AND SUBSEQUENT EVENTS	19, 20		
SHAREHOLDERS' EQUITY			
Share capital	14	**728,934**	685,898
Contributed surplus		**11,495**	12,791
Accumulated other comprehensive income		**3,824**	3,761
Retained earnings (deficit)		**(109,055)**	(34,809)
		635,198	667,641
		1,042,938	1,000,531

See accompanying notes to these financial statements.

On behalf of the Board:

GEORGE F. FINK
Director

RODGER A. TOURIGNY
Director

→ STATEMENT OF COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31 ($ 000s, except $ per share)	Note	**2014**	2013
REVENUE			
Oil and gas sales, net of royalties	15	**301,584**	257,777
Loss on risk management contracts	17	**-**	(1,202)
Other income	16	**2,111**	760
		303,695	257,335
EXPENSES			
Production		**66,878**	56,810
Office and administration		**3,559**	4,456
Employee compensation		**7,111**	5,986
Finance costs	4	**7,104**	8,211
Share-based payments	14	**2,725**	4,155
Depletion and depreciation	7	**106,697**	91,779
Exploration and evaluation	6	**28**	1,156
		194,102	172,553
EARNINGS BEFORE INCOME TAXES		**109,593**	84,782
TAXES			
Current income taxes	13	**10,505**	-
Deferred income taxes	13	**60,327**	22,024
		70,832	22,024
NET EARNINGS FOR THE YEAR		**38,761**	62,758
OTHER COMPREHENSIVE INCOME			
Unrealized gain on investments		**1,174**	2,725
Deferred taxes on unrealized gain on investments		**(147)**	(341)
Realized gain on investments transferred to net earnings		**(1,102)**	(278)
Deferred taxes on realized gain on investments transferred to net earnings		**138**	35
OTHER COMPREHENSIVE INCOME FOR THE YEAR		**63**	2,141
TOTAL COMPREHENSIVE INCOME FOR THE YEAR		**38,824**	64,899
NET EARNINGS PER SHARE – BASIC	14	**1.21**	2.08
NET EARNINGS PER SHARE – DILUTED	14	**1.21**	2.07
COMPREHENSIVE INCOME PER SHARE – BASIC	14	**1.22**	2.15
COMPREHENSIVE INCOME PER SHARE – DILUTED	14	**1.21**	2.14

See accompanying notes to these financial statements.

→ STATEMENT OF CASH FLOW

FOR THE YEARS ENDED DECEMBER 31 ($ 000s)	Note	**2014**	2013
OPERATING ACTIVITIES			
Net earnings		**38,761**	62,758
Items not affecting cash			
Deferred income taxes		**60,327**	22,024
Share-based payments		**2,725**	4,155
Depletion and depreciation		**106,697**	91,779
Exploration and evaluation		**28**	1,156
Unrealized gain on risk management contracts		**-**	(1,859)
Unwinding of the discount on decommissioning liabilities	12	**1,361**	1,088
Gain on sale of properties		**(671)**	(217)
Gain on sale of investments		**(1,102)**	(278)
Investment income		**(56)**	(104)
Interest expense		**5,743**	7,123
Change in non-cash working capital accounts:			
Accounts receivable		**8,411**	(1,492)
Crude oil inventory		**(258)**	116
Prepaid expenses		**(786)**	909
Investment tax credit receivable		**6,646**	-
Accounts payable and accrued liabilities		**1,922**	(5,530)
Decommissioning expenditures	12	**(1,652)**	(609)
Interest paid		**(5,743)**	(7,123)
CASH PROVIDED BY OPERATING ACTIVITIES		**222,353**	173,896
FINANCING ACTIVITIES			
Decrease in bank debt		**(2,041)**	(10,044)
Subordinated promissory note		**15,000**	10,000
Issuance of common shares		**-**	27,603
Share issue costs		**-**	(1,325)
Stock option proceeds		**37,911**	6,625
Dividends		**(113,007)**	(100,180)
CASH USED IN FINANCING ACTIVITIES		**(62,137)**	(67,321)
INVESTING ACTIVITIES			
Investment income received		**56**	104
Exploration and evaluation expenditures	6	**(402)**	(36)
Property, plant and equipment expenditures	7	**(155,262)**	(121,605)
Proceeds on sale of properties		**1,152**	2,414
Purchase of investments		**(1,527)**	-
Proceeds on sale of investments		**1,539**	968
Cash acquired on acquisition	18	**-**	10,000
Change in non-cash working capital accounts:			
Accounts payable and accrued liabilities		**(4,344)**	(2,408)
Accounts receivable		**(1,428)**	3,988
CASH USED IN INVESTING ACTIVITIES		**(160,216)**	(106,575)
NET CASH INFLOW		**-**	-
Cash, beginning of year		**-**	-
CASH, END OF YEAR		**-**	-

See accompanying notes to these financial statements.

→ STATEMENT OF CHANGES IN EQUITY

FOR THE YEARS ENDED
($ 000s, except number of shares outstanding)

	Number of shares outstanding (Note 14)	Share capital (Note 14)	Contributed surplus[1]	Accumulated other comprehensive income[2]	Retained earnings (deficit)	Total shareholders' equity
JANUARY 1, 2013	19,909,541	149,877	9,167	1,620	2,613	163,277
Share-based payments			4,155			4,155
Acquisition	10,711,405	502,258				502,258
Share issuance	553,725	27,603				27,603
Share issue costs, net of tax		(996)				(996)
Exercise of options	147,500	6,625				6,625
Transfer to share capital on exercise of options		531	(531)			-
Comprehensive income				2,141	62,758	64,899
Dividends					(100,180)	(100,180)
DECEMBER 31, 2013	31,322,171	685,898	12,791	3,761	(34,809)	667,641
Share-based payments			2,725			2,725
Exercise of options	829,452	37,911				37,911
Transfer to share capital on exercise of options		4,021	(4,021)			-
Shares issued for oil and gas properties	18,000	1,104				1,104
Comprehensive income				63	38,761	38,824
Dividends					(113,007)	(113,007)
DECEMBER 31, 2014	**32,169,623**	**728,934**	**11,495**	**3,824**	**(109,055)**	**635,198**

(1) Contributed surplus is comprised of share-based payments
(2) Accumulated other comprehensive income comprises of unrealized gains and losses on available-for-sale investments

See accompanying notes to these financial statements.

Notes to the **Financial Statements**

As at and for the years ended December 31, 2014 and 2013.

→ 1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. (Bonterra or the Company) is a public company listed on the Toronto Stock Exchange and incorporated under the Business Corporations Act (Alberta). The address of the Company's registered office is Suite 901, 1015-4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

Bonterra operates in one industry and has only one reportable segment being the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

→ 2. BASIS OF PREPARATION

a) Statement of Compliance

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB).

The financial statements were authorized for issuance by the Company's Board of Directors on March 19, 2015.

b) Basis of Measurement

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payment transactions which are measured at fair value.

c) Functional and Presentation Currency

The Company's functional and presentation currency is the Canadian dollar.

Foreign currency denominated monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the reporting date. Non-monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the period in which they occur.

d) Significant Accounting Estimates and Judgments

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. The following are the estimates and judgments applied by management that most significantly affect the Company's financial statements.

Exploration and Evaluation Expenditures

Exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. Exploration and evaluation assets include undeveloped land and costs related to exploratory wells. The Company is required to make estimates and judgments about future events and circumstances regarding the future economic viability of extracting the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made, that the underlying reserves are not viable, the exploration and evaluation costs will be impaired and charged to net earnings.

Impairment of Non-Financial Assets

Property, plant and equipment and goodwill are aggregated into cash generating units (CGUs) based on their ability to generate largely independent cash flows and are assessed for impairment. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, and similar market risks. Oil and gas prices and other assumptions will change in the future, which may impact the Company's recoverable amounts and may therefore require a material adjustment to the carrying value of property, plant and equipment. The determination of the Company's CGUs is subject to management's judgment.

Reserves Estimation

The capitalized costs of oil and gas properties are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors and future oil and gas prices. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves.

Risk Management Contracts

The Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in net earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party futures quotes for commodities. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

Share-Based Payments

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value requires the determination of the most appropriate valuation model for a grant, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk free interest rates, volatility and dividend yield.

Decommissioning and Restoration Costs

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of the Company's oil and gas properties. Provisions for decommissioning liabilities are based on cost estimates which can vary in response to many factors including timing of abandonment, inflation, changes in legal requirements, new restoration techniques and interest rates.

Income Taxes

The Company recognizes the net deferred tax benefit or expense related to deferred income tax assets or liabilities to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of investment tax credit receivable requires the Company to make significant estimates related to expectations of future taxable income. The provision for income taxes is based on judgments in applying income tax law and estimates of the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. The ability to realize on the deferred tax assets and investment tax credit receivable recorded on the balance sheet may be compromised to the extent that any interpretation of tax law is challenged or taxable income differs significantly from estimates.

Further details regarding accounting estimates and judgments are disclosed in Note 3.

e) Adopted Accounting Pronouncements

As of January 1, 2014, the Company adopted several new IFRS interpretations and amendments in accordance with the transitional provisions of each standard. A brief description of each new accounting policy and its impact on the Company's financial statements are as follows:

IAS 32 "Financial Instruments: Presentation"

Has been amended to clarify certain criteria required to be achieved in order to permit the offsetting of financial assets and financial liabilities. The retrospective adoption of the amendment does not have any impact on Bonterra's financial statements.

IAS 36 "Impairment of Assets"

Has been amended to reduce the circumstances in which the recoverable amount of cash generating units ("CGUs") is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in a period. The retrospective adoption of these amendments will only impact Bonterra's disclosures in the financial statements in periods when an impairment loss or impairment reversal is recognized.

IAS 39 "Financial Instruments: Recognition and Measurement"

Has been amended to clarify that there would be no requirement to discontinue hedge accounting if a hedging derivative was novated, provided certain criteria are met. The retrospective adoption of the amendment does not have any impact on Bonterra's financial statements.

IFRIC 21 "Levies"

Was developed by the IFRS Interpretations Committee (IFRIC) and is applicable to all levies imposed by governments under legislation, other than outflows that are within the scope of other standards (e.g., IAS 12 "Income Taxes") and fines or other penalties for breaches of legislation. The interpretation clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. It also clarifies that a levy liability is accrued progressively only if the activity that triggers payment occurs over a period of time, in accordance with the relevant legislation. Lastly, the interpretation clarifies that a liability should not be recognized before the specified minimum threshold to trigger that levy is reached. The retrospective adoption of this interpretation does not have any impact on Bonterra's financial statements.

f) Future Accounting Pronouncements

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. This standard is required to be adopted either retrospectively or using a modified transition approach for fiscal years beginning on or after January 1, 2017, with earlier adoption permitted. The Company has not yet assessed the impact, if any, that the new amended standard will have on its financial statements or whether to early adopt this new requirement.

In July 2014, the IASB has amended IFRS 9 "Financial Instruments", which amends its classification and measurement of financial assets and introduces a new expected loss impairment model. This standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted and shall be applied retrospectively. The Company has not yet assessed the impact, if any, that the new standard will have on its financial statements or whether to early adopt this new standard.

→ 3. SIGNIFICANT ACCOUNTING POLICIES

a) Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when the significant risks and rewards of ownership have been transferred to the customer. This generally occurs when the product is physically transferred into a third-party pipeline or when the delivery truck arrives at a customer's receiving location. Items such as royalties for crown, freehold, gross overriding (GORR) and Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue.

Administration fee income is recorded when management services and office administration are provided (see related parties disclosure Notes 9 and 16).

b) Joint Arrangements

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's interests in such activities. A jointly controlled operation involves the use of assets and other resources of the Company and those of other venturers through contractual arrangements rather than through the establishment of a corporation, partnership or other entity. The Company has no interests in jointly controlled entities. The Company recognizes in its financial statements its interest in assets that it owns, the liabilities and expenses that it incurs and its share of income earned by the joint arrangement.

c) Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first in first out basis at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, depletion and depreciation for the period and net realizable value is determined based on estimated sales price less transportation costs.

d) Investments and Investment in Related Party

Investments and investment in related party consist of equity securities classified on initial recognition as available-for-sale and are carried at fair value through other comprehensive income. Fair value is determined by multiplying the period end trading price of the investments by the number of common shares held as at period end. Unrealized holding gains and losses are recognized in other comprehensive income. Net gains and losses arising on dispositions are recognized in net earnings.

e) Exploration and Evaluation Assets

General exploration and evaluation (E&E) expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the asset. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment (PP&E). E&E assets are assessed for impairment annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not at amounts above their recoverable amounts.

f) Property, Plant and Equipment

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

When commercial production in an area has commenced, PP&E properties, excluding surface costs are depleted using the unit-of-production method over their total developed reserve life. Total developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of total developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost, including expenditures such as drilling costs, the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset and finance charges on qualifying assets, that are directly attributable to bringing the asset into operation in its present location.

Production Facilities

Production facilities are comprised of costs related to petroleum and natural gas plant and production equipment.

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income. Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets' estimated economic lives, less estimated salvage value of the assets at the end of their useful lives.

These assets are depreciated on a declining balance method as follows:

Production facilities	10 percent per year
Furniture, fixtures and other equipment	10 percent to 20 percent per year

g) Business Combinations and Goodwill

The purchase price used in a business combination is based on the fair value at the date of acquisition. The business combination is accounted for based on the fair value of the assets acquired and liabilities assumed. All acquisition costs are expensed as incurred. Contingent liabilities are recognized at fair value at the date of the acquisition, and subsequently re-measured at each reporting period until settled. The excess of cost over fair value of the net assets and liabilities acquired is recorded as goodwill. Goodwill is allocated to the CGU expected to benefit from the synergies of the combination.

h) Impairment of Assets

Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flow of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flow discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its current fair value.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as available-for-sale is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets' carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E, PP&E and Goodwill) are grouped together into the smallest group of assets that generates cash flows from continuing use that are largely independent of the cash flow of other assets or groups of assets (the cash-generating unit or CGU). The recoverable amount of an asset or a CGU is the greater of its value-in-use (VIU) and its fair value less costs to sell (FVLCS).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income. Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

In respect of assets other than goodwill, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the impairment loss has reversed. If the amount of the impairment loss reverses in a subsequent period and the reversal can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized and recorded in the statement of comprehensive income. An impairment loss in respect of goodwill cannot be reversed. There was no impairment loss recorded in the statement of comprehensive income for the years ended December 31, 2014 and 2013.

i) Decommissioning Liabilities

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk free rates are dealt with prospectively by recording an adjustment to the decommissioning liability and a corresponding adjustment to property, plant and equipment. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the liability can be made. On a periodic basis, management will review these estimates and changes and if there are any, they will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved plus probable developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and any remaining balance of actual costs is recorded in the statement of comprehensive income.

j) Income Taxes

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each balance date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset or liability.

k) Share-Based Payments

The Company accounts for share-based payments using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Share-based payments are recognized through the statement of comprehensive income over the vesting period with a corresponding amount reflected in contributed surplus in equity. For awards issued in tranches that vest at different times, the fair value of each tranche is recognized over its respective vesting period.

At the grant date and at the end of each reporting period, the Company assesses and re-assesses for subsequent periods its estimates of the number of awards that are expected to vest and recognizes the impact of the revisions in the statement of comprehensive income. Upon exercise of share-based options, the proceeds received net of any transaction costs and the fair value of the exercised share-based options is credited to share capital.

Employees may elect to have the Company settle any or all options vested and exercisable using a cashless equity settlement. In connection with any such exercise, an employee shall be entitled to receive, without any cash payment (other than the taxes required to be paid in connection with the exercise), whole shares of the Company. The number of shares under option multiplied by the difference of the fair value at the time of exercise less the option exercise price, divided by the fair value at the time of exercise, determines the number of whole shares issued.

l) Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair-value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets and financial liabilities at amortized cost.

Subsequent measurement of financial instruments is based on their initial classification. Fair-value through profit or loss financial instruments are measured at fair value and changes in fair value are recognized in the statement of comprehensive income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

Cash is classified as fair-value through profit and loss. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments are classified as available-for-sale which is measured at fair value and any gains or losses are recognized in other comprehensive income in the period they occur. Accounts payable and accrued liabilities, bank debt, subordinated promissory note and amounts due to related party are classified as financial liabilities at amortized cost.

Bank debt, subordinated promissory note and due to related party are classified as current liabilities unless the Company has an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

m) Risk Management Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

n) Net Earnings and Comprehensive Income Per Share

Per share amounts are calculated by dividing the net earnings or comprehensive income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

→ 4. FINANCE COSTS

A breakdown of finance costs for the years ended.

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Interest expense on bank debt	**4,283**	6,165
Interest expense on amounts owing to related party	**285**	285
Interest expense on subordinated promissory note and other	**1,175**	673
Unwinding of the fair value of decommissioning liabilities	**1,361**	1,088
	7,104	8,211

→ 5. INVESTMENT IN RELATED PARTY

The investment consists of 1,034,523 (December 31, 2013 – 1,034,523) common shares in Pine Cliff Energy Ltd. (Pine Cliff), a company with some common directors and some common management with Bonterra. The investment in Pine Cliff represents less than one percent ownership in the outstanding common shares of Pine Cliff and is recorded at fair value through other comprehensive income. The common shares of Pine Cliff trade on the TSX Venture Exchange under the symbol PNE.

In addition, Geomark Exploration Ltd. (a wholly owned subsidiary of Pine Cliff) owns 204,633 (December 31, 2013 – 204,633) common shares in Bonterra.

→ 6. EXPLORATION AND EVALUATION ASSETS

($ 000s)	
COST AND CARRYING AMOUNT	
Balance at January 1, 2013	1,982
Acquisition (Note 18)	8,830
Additions	36
Dispositions	(1,373)
Transfers to property, plant and equipment	(645)
Expiry of exploration and evaluation assets	(1,156)
BALANCE AT DECEMBER 31, 2013	**7,674**
Additions	402
Dispositions	(419)
Expiry of exploration and evaluation assets	(28)
BALANCE AT DECEMBER 31, 2014	**7,629**

In January 2014, the Company sold a portion of its undeveloped land in the Willesden Green area for cash proceeds of $1,000,000. At the time of disposition, the Company had a carrying value of $419,000 for these exploration and evaluation expenditures, resulting in a gain on sale of $581,000.

→ 7. PROPERTY, PLANT AND EQUIPMENT

COST ($ 000s)	**OIL AND GAS PROPERTIES**	**PRODUCTION FACILITIES**	**FURNITURE, FIXTURES & OTHER EQUIPMENT**	**TOTAL PROPERTY, PLANT & EQUIPMENT**
Balance at January 1, 2013	427,241	94,902	1,661	523,804
Additions	92,492	28,799	314	121,605
Adjustment to decommissioning liabilities (1)	(6,100)	-	-	(6,100)
Dispositions	(797)	(205)	(35)	(1,037)
Transfers from exploration and evaluation assets	645	-	-	645
Acquisition (Note 18)	378,685	92,454	-	471,139
BALANCE AT DECEMBER 31, 2013	892,166	215,950	1,940	1,110,056
Additions	119,635	36,633	47	156,315
Adjustment to decommissioning liabilities (1)	16,721	-	-	16,721
Dispositions	(2)	(62)		(64)
BALANCE AT DECEMBER 31, 2014	**1,028,520**	**252,521**	**1,987**	**1,283,028**

ACCUMULATED DEPLETION AND DEPRECIATION ($ 000s)	**OIL AND GAS PROPERTIES**	**PRODUCTION FACILITIES**	**FURNITURE, FIXTURES & OTHER EQUIPMENT**	**TOTAL PROPERTY, PLANT & EQUIPMENT**
Balance at January 1, 2013	(143,607)	(37,521)	(1,224)	(182,352)
Depletion and depreciation	(73,885)	(17,766)	(128)	(91,779)
Dispositions and other	(30)	9	31	10
BALANCE AT DECEMBER 31, 2013	(217,522)	(55,278)	(1,321)	(274,121)
Depletion and depreciation	(88,001)	(18,588)	(108)	(106,697)
Dispositions and other	(219)	-	-	(219)
BALANCE AT DECEMBER 31, 2014	**(305,742)**	**(73,866)**	**(1,429)**	**(381,037)**

CARRYING AMOUNTS AS AT: ($ 000s)				
December 31, 2013	674,644	160,672	619	835,935
DECEMBER 31, 2014	**722,778**	**178,655**	**558**	**901,991**

(1) Adjustment to decommissioning liabilities is due to a decrease in the risk free rate and a change in estimate on decommissioning costs (see Note 12).

Impairment

As part of its annual impairment analysis, the Company assessed its PP&E assets, production facilities, furniture and other equipment by CGU for possible impairment.

The assessment for impairment has been determined based on the value-in-use (VIU) method. VIU was determined on the basis of the discounted expected future cash flows based on the Company's plans to continue to produce total proved and probable reserves.

Projected estimates of cash flows from the CGUs have been determined based on the economic life of the reserves using an inflation rate of 1.5 percent (2013 – 1.5 percent). The pre-tax discount rate applied to the cash flows for the Company's total proved and probable assets is ten percent.

There were no impairment provisions recorded for the years ended December 31, 2014 and 2013.

→ 8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

($ 000s)	DECEMBER 31, 2014	December 31, 2013
Accounts payable	**15,170**	18,966
Accrued liabilities	**16,669**	15,295
	31,839	34,261

→ 9. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2014, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2013 – $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during the year was $285,000 (December 31, 2013 – $285,000).

The Company received a management fee of $60,000 plus the reimbursement of certain administrative costs for the year ended December 31, 2014 (December 31, 2013 – $60,000) for management services and office administration from Pine Cliff. This fee has been included in other income. As at December 31, 2014, the Company had an account receivable from Pine Cliff for these management fees and the reimbursement of certain administration costs of $316,000 (December 31, 2013 – $217,000).

Compensation for Key Management Personnel

($ 000s)	DECEMBER 31, 2014	December 31, 2013
Compensation	**2,272**	1,542
Share-based payments	**1,120**	1,876
Total compensation	**3,392**	3,418

Key management personnel are those persons, including all directors, having authority and responsibility for planning, directing and controlling the activities of the Company.

→ 10. SUBORDINATED PROMISSORY NOTE

As at December 31, 2014, Bonterra borrowed $40,000,000 (December 31, 2013 – $25,000,000) from a private investor, in exchange for a subordinated promissory note. The terms of the subordinated promissory note are that it bears interest at three percent and is repayable after thirty days written notice by either party. Security consists of a floating demand debenture totaling $40,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on the subordinated promissory note during the year was $1,175,000 (December 31, 2013 – $673,000).

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility.

→ 11. BANK DEBT

As at December 31, 2014, the Company has bank facilities consisting of a $220,000,000 (December 31, 2013 – $220,000,000) syndicated revolving credit facility and a $30,000,000 (December 31, 2013 – $30,000,000) non-syndicated revolving credit facility, for total facilities of $250,000,000. Amounts drawn under the credit facilities at December 31, 2014 were $154,723,000 (December 31, 2013 – $156,764,000). Amounts borrowed under the credit facilities bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 0.75 percent and 3.50 percent, depending on the type of borrowing and the Company's consolidated total funded debt to consolidated cash flow. The terms of the revolving credit facilities provided that the loan is revolving to April 30, 2015 and with a maturity date of April 30, 2016 and is subject to annual review. The revolving credit facilities have no fixed terms of repayment.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $700,000 were issued as at December 31, 2014 (December 31, 2013 – $700,000). Security for credit facilities consists of various and floating demand debentures totaling $400,000,000 (December 31, 2013 – $400,000,000) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

The following is a list of the material covenants on the banking facility:

- The Company cannot exceed $250,000,000 in consolidated debt (includes working capital but excludes amounts due to related parties and the subordinated promissory note).
- Dividends paid in the current quarter shall not exceed 80 percent of the average available cash flow for the preceding four fiscal quarters.

Available cash flow is defined to be cash provided by operating activities excluding gains on sale of property and investments, the change in non-cash working capital and decommissioning liabilities settled and including all net proceeds of dispositions included in cash used in investing activities. At December 31, 2014, the Company is in compliance with all covenants.

→ 12. DECOMMISSIONING LIABILITIES

At December 31, 2014, the estimated total undiscounted amount required to settle the decommissioning liabilities was $177,441,000 (December 31, 2013 – $134,265,000). The provision has been calculated assuming a 1.5 percent inflation rate (December 31, 2013 – 1.5 percent inflation rate). These obligations will be settled at the end of the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of 2.9 percent (December 31, 2013 – 3.2 percent).

Changes to decommissioning liabilities were as follows:

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Decommissioning liabilities, January 1	**37,362**	34,246
Adjustment to decommissioning liabilities[1]	**16,721**	(6,100)
Acquisition (Note 18)	**-**	8,870
Dispositions	**-**	(133)
Liabilities settled during the year	**(1,652)**	(609)
Unwinding of the discount on decommissioning liabilities	**1,361**	1,088
Decommissioning liabilities, end of year	**53,792**	37,362

(1) Adjustment to decommissioning liabilities is due to a change in the discount rate and estimates.

→ 13. INCOME TAXES

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Deferred tax asset (liability) related to:		
Investments	**(566)**	(572)
Exploration and evaluation assets and property, plant and equipment	**(126,199)**	(114,027)
Investment tax credits	**(3,808)**	(6,923)
Decommissioning liabilities	**13,459**	9,348
Corporate tax losses carried forward	**-**	42,582
Share issue costs	**1,162**	1,517
Corporate capital tax losses carried forward	**8,617**	16,880
Unrecorded benefit of capital tax losses carried forward	**(8,051)**	(16,308)
Deferred tax asset (liability)	**(115,386)**	(67,503)

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Earnings before taxes	**109,593**	84,782
Combined federal and provincial income tax rates	**25.02%**	25.02%
Income tax provision calculated using statutory tax rates	**27,420**	21,212
Increase (decrease) in taxes resulting from:		
Share-based payments	**682**	1,040
Unrecorded benefit of capital tax losses	**-**	(354)
Change in estimates	**(578)**	207
Effect of Agreement	**43,503**	-
Other	**(195)**	(81)
Income tax expense	**70,832**	22,024

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	91,847
Eligible capital expenditures	7	3,364
Share issue costs	20	4,643
Canadian oil and gas property expenditures	10	61,936
Canadian development expenditures	30	238,391
Canadian exploration expenditures	100	8,063
		408,244

The Company has $8,573,000 (December 31, 2013 – $27,670,000) of investment tax credits that expire in the following years; 2021 – $1,662,000; 2022 – $1,735,000; 2023 – $1,097,000; 2024 – $1,241,000; 2025 – $1,323,000; 2026 – $1,105,000; and 2027 – $410,000.

The Company has $68,881,000 (December 31, 2013 – $134,938,000) of capital losses carried forward which can only be claimed against taxable capital gains.

On November 14, 2013, the Company received a proposal letter from the Canada Revenue Agency (CRA) which stated its intention to challenge the tax consequences of Bonterra's reorganization from a trust to a Corporation, which occurred on November 18, 2008. On November 27, 2014, the Company reached an agreement with CRA (the Agreement) to adjust certain tax pools, resulting in a $43,503,000 reduction in the Company's deferred tax assets and investment tax credit receivable. The reduction was charged to deferred tax expense in the statement of comprehensive income. Of the $10,505,000 current tax provision, $6,645,000 of the federal investment tax credit receivable was used to reduce current taxes payable to $3,860,000.

→ 14. SHAREHOLDERS' EQUITY

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

	DECEMBER 31, 2014		December 31, 2013	
Issued and fully paid – common shares	**NUMBER**	**AMOUNT ($ 000S)**	Number	Amount ($ 000s)
Balance, beginning of year	**31,322,171**	**685,898**	19,909,541	149,877
Acquisition	**-**	**-**	10,711,405	502,258
Share issuance	**-**	**-**	553,725	27,603
Share issue costs, net of tax		**-**		(996)
Issued pursuant to the Company's share option plan	**829,452**	**37,911**	147,500	6,625
Transfer from contributed surplus to share capital		**4,021**		531
Shares issued for oil and gas properties	**18,000**	**1,104**	-	-
Balance, end of year	**32,169,623**	**728,934**	31,322,171	685,898

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 weighted average common shares used to calculate basic and diluted net earnings per share for the year ended December 31 is as follows:

	2014	2013
Basic shares outstanding	**31,921,623**	30,210,710
Dilutive effect of share options[1]	**114,022**	108,315
Diluted shares outstanding	**32,035,645**	30,319,025

(1) The Company did not include 1,100,000 share options (December 31, 2013 – 226,000) in the dilutive effect of share options calculation as these share options were anti-dilutive.

For the year ended December 31, 2014, the Company declared and paid dividends of $113,007,000 ($3.54 per share) (December 31, 2013 – $100,180,000 ($3.33 per share)).

The Company provides an equity settled option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,216,962 (December 31, 2013 – 3,132,217) common shares. The exercise price of each option granted cannot be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2014, and changes during the period ended on those dates is presented below:

	NUMBER OF OPTIONS	**WEIGHTED AVERAGE EXERCISE PRICE**
At January 1, 2013	1,902,000	$ 49.99
Options granted	365,000	48.68
Options exercised	(147,500)	44.91
Options cancelled	(380,000)	57.76
Options forfeited	(89,000)	51.00
At December 31, 2013	1,650,500	$ 48.31
Options granted	1,769,000	56.48
Options exercised	(904,000)	47.09
Options forfeited	(194,000)	49.09
Options expired	(210,000)	55.01
AT DECEMBER 31, 2014	**2,111,500**	**$ 54.94**

The following table summarizes information about options outstanding at December 31, 2014:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number outstanding at December 31, 2014	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2014	Weighted-average exercise price
$ 40.00 – $ 50.00	326,000	1.0 years	$ 46.16	103,000	$ 44.51
50.01 – 60.00	986,500	1.0 years	52.76	81,500	52.91
60.01 – 65.00	799,000	1.8 years	61.21	-	-
$ 40.00 – $ 65.00	2,111,500	1.3 years	$ 54.83	184,500	$ 48.22

The Company records compensation expense over the vesting period, which ranges between one to three years, based on the fair value of options granted to employees, directors and consultants. In 2014, the Company granted 1,769,000 stock options with an estimated fair value of $4,989,000 or $2.82 per option using the Black-Scholes option pricing model with the following key assumptions:

	DECEMBER 31, 2014	December 31, 2013
Weighted-average risk free interest rate (%)[1]	**1.04**	1.15
Expected life (years)	**1.5**	1.88
Weighted-average volatility (%)[2]	**17.63**	26.61
Forfeiture rate (%)	**5.0**	-
Weighted average dividend yield (%)	**5.66**	6.91

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for one, two, and three year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

The weighted average share price when the options were exercised in 2014 were $56.41 (2013 – $53.86)

→ 15. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Oil and gas sales	**339,694**	295,675
Less:		
Crown royalties	**(23,779)**	(18,031)
Freehold, gross overriding royalties and other	**(14,331)**	(19,867)
Oil and gas sales, net of royalties	**301,584**	257,777

→ 16. OTHER INCOME

($ 000s)	**DECEMBER 31, 2014**	December 31, 2013
Investment income	**56**	104
Administrative income	**282**	161
Gain on sale of properties	**671**	217
Realized gain on investments	**1,102**	278
Other income	**2,111**	760

→ 17. FINANCIAL AND CAPITAL RISK MANAGEMENT

Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Common share investments
- Due to related party
- Bank debt
- Subordinated promissory note

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, liquidity risk and equity price risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

The Company may enter into various risk management contracts to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Capital Risk Management

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of net debt (total debt adjusted for working capital) to cash flow. This ratio is calculated using each quarter end net debt and divided by the preceding twelve months cash flow. Management believes that a net debt level as high as one and a half year's cash flow is still an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs. During the current year the Company achieved a net debt to annual cash flow level of 0.9:1.

Section (a) of this note provides a summary of the Company's underlying economic positions as represented by the carrying values, fair values and contractual face values of the Company's financial assets and financial liabilities. The Company's debt to cash flow from operations is also provided.

Section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

Section (c) provides details of the Company's risk management contracts that are used for financial risk management.

a) Financial assets, financial liabilities and net debt ratio

The carrying amounts and fair values of the Company's financial assets and liabilities are shown in the table as follows.

	AS AT DECEMBER 31, 2014		As at December 31, 2013	
($ 000s)	CARRYING VALUE	FAIR VALUE	Carrying Value	Fair Value
FINANCIAL ASSETS				
Accounts receivable	**20,314**	**20,314**	27,247	27,247
Investments	**6,228**	**6,228**	5,728	5,728
Investments in related party	**1,738**	**1,738**	1,076	1,076
FINANCIAL LIABILITIES				
Accounts payable and accrued liabilities	**31,839**	**31,839**	34,261	34,261
Due to related party	**12,000**	**12,000**	12,000	12,000
Subordinated promissory note	**40,000**	**40,000**	25,000	25,000
Bank debt	**154,723**	**154,723**	156,764	156,764

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related parties, subordinated promissory note and bank debt on the statement of financial position are carried at amortized cost. Investments and investments in related party are carried at fair value. All of the investments are transacted in active markets. Bonterra determines the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

The net debt and cash flow amounts as of December 31, 2014 are as follows:

($ 000s)	
Bank debt	**154,723**
Accounts payable and accrued liabilities	**31,839**
Due to related parties	**12,000**
Subordinated promissory note	**40,000**
Current assets	**(30,197)**
Net debt	**208,365**
Cash flow from operations	**222,353**
Net debt to annual cash flow from operations	**0.9**

b) Risks and mitigation

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

Commodity Price Risk

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts 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.

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $220,000,000 syndicated revolving operating line, $30,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $40,000,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, are at bank prime plus or minus various percentages as well as by means of banker's acceptances (BAs) within the Company's credit facility. The subordinated promissory note is at a fixed interest rate of three percent. The Company manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its BAs but in no circumstances do the terms exceed six months.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $1,250,000.

Equity Price Risk

Equity price risk refers to the risk that the fair value of the investments and investment in related party will fluctuate due to changes in equity markets. Equity price risk arises from the realizable value of the investments that the Company holds which are subject to variable equity market prices which on disposition gives rise to a cash flow equity price risk. The Company will assume full risk in respect of equity price fluctuations.

Foreign Exchange Risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. Management, in agreement with the Board of Directors, decided that at least in the near term it will not use commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

Credit Risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the statement of financial position. To help mitigate this risk:

- The Company only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and
- Agreements for product sales are primarily on 30 day renewal terms.

Of the $20,314,000 accounts receivable balance at December 31, 2014 (December 31, 2013 – $27,247,000) over 80 percent (2013 – 85 percent) relates to product sales with national and international oil and gas companies.

The Company assesses quarterly if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2014, there was no material impairment provision required on any of the financial assets of the Company. The Company does have a credit risk exposure as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days notice if payments are not received.

At December 31, 2014, approximately $2,948,000 or 14.5 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2013 – $3,869,000 or 14.2 percent). The majority of these accounts are due from various joint arrangement partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint arrangement partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2014 is $308,000 (December 31, 2013 – $414,000) with the expense being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable. There are no material financial assets that the Company considers past due.

Liquidity Risk

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company maintains bank facilities determined by a portfolio of high-quality, long reserve life oil and gas assets.

The Company has the following maturity schedule for its financial liabilities and commitments:

($ 000s)	Recognized on Financial Statements	Less than 1 year	Over 1 year to 3 years	4 to 5 years
Accounts payable and accrued liabilities	Yes – Liability	31,839	-	-
Due to related parties	Yes – Liability	12,000	-	-
Subordinated promissory note	Yes – Liability	40,000	-	-
Bank debt	Yes – Liability	-	154,723	-
Office lease commitments	No	957	1,858	307
Total		84,796	156,581	307

c) Risk management contracts

($ 000s)	DECEMBER 31, 2014	December 31, 2013
Risk management contract		
Realized loss	-	(3,061)
Unrealized gain	-	1,859
Other income	-	(1,202)

The Company did not enter into any risk management contracts for the 2014 fiscal year.

→ 18. ACQUISITION

On January 25, 2013, Bonterra acquired 100 percent of the issued and outstanding common shares of Spartan Oil Corp. (Spartan) pursuant to an arrangement agreement (Spartan Transaction). Spartan was a public oil and gas company with properties in Alberta and Saskatchewan. Consideration for Spartan shares was 0.1169 voting common shares of Bonterra, which amounted to the issuance of 10,711,405 Bonterra shares valued at $502,258,000, using the closing share price of $46.89 per share on the date of the Spartan Transaction. The exchange ratio for the transaction represents a deemed price of $5.03 per Spartan Share. The Spartan assets contributed revenue (primarily oil and gas sales, net of royalties) of $92,214,000 and operating and administrative expenses of $11,949,000 for the period from January 25, 2013 to December 31, 2013. If the acquisition had occurred on January 1, 2013, total revenue (primarily oil and gas sales, net of royalties) would have been approximately $99,788,000 and operating and administrative expenses would have been $14,747,000 for the year ended December 31, 2013. The Spartan Transaction was accounted for as a business combination with Bonterra identified as the acquirer.

The purchase price allocation using the acquisition method was allocated to the assets acquired and the liabilities assumed as follows:

NET ASSETS ACQUIRED:	($ 000s)
Exploration and evaluation assets	8,830
Property, plant and equipment	471,139
Goodwill(1)	92,810
Working capital	
Cash	10,000
Accounts receivable	10,585
Prepaid expense	915
Accounts payable and accrued liabilities	(13,597)
Risk management contract	(1,859)
Decommissioning liabilities	(8,870)
Deferred tax liability	(67,695)
Total	502,258

CONSIDERATION AND TOTAL PURCHASE PRICE:	
Bonterra shares (10,711,405 shares at $46.89)	502,258

(1) The amount recorded as goodwill has all been allocated to the primary CGU, Alberta, Canada. Goodwill is recorded at cost and is not amortized.

On March 1, 2013, Spartan was amalgamated with Bonterra.

→ 19. COMMITMENTS

The Company has entered into leases for buildings and office equipment. These leases have an average life of 3.3 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum lease payments under non-cancellable operating leases as at December 31, 2014 are as follows:

($ 000s)	
Within one year	957
After one year but not more than five years	2,165
Total	3,122

→ 20. SUBSEQUENT EVENTS

i) Dividends

Subsequent to December 31, 2014, the Company declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 2, 2015	January 15, 2015	0.30	January 30, 2015
February 2, 2015	February 13, 2015	0.15	February 27, 2015
March 2, 2015	March 16, 2015	0.15	March 31, 2015

ii) Acquisition of Pembina Alberta Oil and Gas Assets

On February 19, 2015, the Company entered into a purchase and sale agreement to acquire Cardium focused oil and gas assets in the Pembina area of Alberta, including upper zones in the Belly River (the Pembina Assets). Consideration for the Pembina Assets is $172,000,000, prior to any adjustments, which will be initially financed by a combination of working capital and an increased debt facility. The purchase price allocation using the acquisition method for the Pembina Assets is incomplete as of March 19, 2015.

Corporate **Information**

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BOARD OF DIRECTORS

G. F. Fink
G. J. Drummond
R. M. Jarock
C. R. Jonsson
R. A. Tourigny

OFFICERS

G. F. Fink, CEO and Chairman of the Board
R. D. Thompson, CFO and Corporate Secretary
A. Neumann, Chief Operating Officer
B. A. Curtis, Vice President, Business Development

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada, Calgary, Alberta

AUDITORS

Deloitte LLP, Calgary, Alberta

SOLICITORS

Borden Ladner Gervais LLP, Calgary, Alberta

BANKERS

CIBC, Calgary, Alberta
National Bank of Canada, Calgary, Alberta
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