Efficient.
Sustainable.
Disciplined.

BONTERRA ENERGY CORP. 2015 ANNUAL REPORT

Efficient. Sustainable. Disciplined.

BONTERRA ENERGY CORP. IS A DIVIDEND-PAYING, CONVENTIONAL OIL AND GAS COMPANY FOCUSED ON GROWING FUNDS FLOW, PRODUCTION AND RESERVES ON A PER SHARE BASIS. THE COMPANY'S HIGH QUALITY ASSET BASE, CONSERVATIVE FINANCIAL MANAGEMENT AND STRONG CAPITAL EFFICIENCIES POSITION BONTERRA FOR LONG-TERM SUSTAINABILITY ACROSS A VARIETY OF COMMODITY PRICE CYCLES.

HIGH QUALITY ASSETS

Bonterra's assets are concentrated in the Pembina Cardium, a well-delineated, low-risk reservoir containing an estimated 10.6 billion barrels of oil in place with less than 13% produced to date. As one of the area's largest operators, Bonterra has over 200 net sections of land and over 20 years of drilling inventory including 230+ net booked and 770+ net identified low-risk locations. Access to infrastructure supports high netback, low-decline, and light oil production growth.

Low Production Decline

18%

DRIVING DOWN WELL COSTS

Per well capital costs to drill, complete and tie-in (DC&T) were lowered in 2015 by approximately 27% through a combination of increased technology, pad drilling and lower industry cost structure. Bonterra's improved operational efficiencies contributed to significant structural cost reductions that can be maintained through future cost fluctuations. Further, increased collaboration on frac design and reservoir simulations enabled the Company to streamline drilling and completion techniques while building important intellectual capital that supports enhanced efficiencies going forward.

DC&T Costs

↓27%

IMPROVED GAS TRANSPORTATION

Late in 2015, Bonterra increased its firm transportation service commitments from 30% previously to 90% going forward, which greatly improves access to markets. The importance of consistent and reliable infrastructure was demonstrated during 2015 as Bonterra experienced production impacts caused by non-operated facility and transportation issues.

90%

Natural Gas Production on Firm Transportation

REDUCED OPERATING COSTS

Bonterra successfully reduced 2015 operating expenses (opex) per BOE by approximately 14% over 2014 through a combination of field optimizations leading to reduced well maintenance, more efficient produced-water handling and decreased chemical costs. The Company will continue to control expenses and seek opportunities for further opex reductions through reduced trucking, waterflood support and lower labour costs.

2015 OPEX

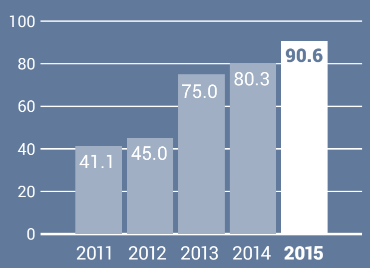
↓14%

to $11.95 per BOE

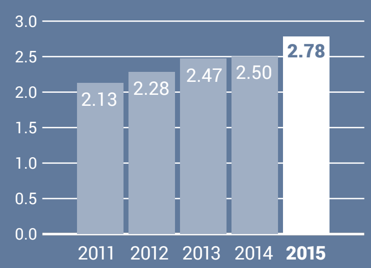
FINANCIAL FLEXIBILITY SUPPORTS GROWTH

Bonterra continues to explore ways to enhance recoveries and reduce costs through the use of technology and increased well density, and will prudently allocate capital to opportunities offering the best results and highest economic returns. Maintaining financial flexibility enables Bonterra to grow production and reduce debt, while positioning the Company to increase capital spending, dividends or a combination of the two when commodity prices stabilize at higher levels.

P+P RESERVES GROWTH
(mmboe)



RESERVES PER SHARE
(proved + probable reserves)



ANNUAL HIGHLIGHTS

As at and for the year ended ($ 000s except $ per share)		DECEMBER 31, 2015[1]	December 31, 2014	December 31, 2013[3]
FINANCIAL				
Revenue – realized oil and gas sales		**197,239**	339,694	295,675
Funds flow[5]		**117,948**	209,665	181,574
Per share – basic		**3.61**	6.57	6.01
Per share – diluted		**3.61**	6.54	5.99
Payout ratio		**54%**	54%	55%
Cash flow from operations		**107,871**	222,353	173,896
Per share – basic		**3.30**	6.97	5.76
Per share – diluted		**3.30**	6.94	5.74
Payout ratio		**59%**	51%	58%
Cash dividends per share		**1.95**	3.54	3.33
Earnings before income taxes		**1,982**	109,593	84,782
Net earnings (loss)		**(9,080)**	38,761	62,758
Per share – basic		**(0.28)**	1.21	2.08
Per share – diluted		**(0.28)**	1.21	2.07
Capital expenditures, net of dispositions		**58,498**	155,565	119,227
Acquisition		**170,430**[2]	-	502,258[4]
Total assets		**1,183,593**	1,042,938	1,000,531
Working capital deficiency		**29,804**	53,642	35,985
Long-term debt		**332,471**	154,723	156,764
Shareholders' equity		**595,805**	635,198	667,641
OPERATIONS				
Oil	– bbl per day	**8,641**	8,582	7,787
	– average price ($ per bbl)	**54.08**	90.61	89.26
NGLs	– bbl per day	**733**	807	744
	– average price ($ per bbl)	**20.80**	52.26	52.41
Natural gas	– mcf per day	**19,694**	22,833	21,954
	– average price ($ per mcf)	**2.94**	4.86	3.46
Total barrels of oil equivalent (BOE) per day[6]		**12,656**	13,195	12,190

(1) Annual figures for 2015 include the results of a purchase (the Acquisition) of primarily Pembina Cardium oil and gas assets (Pembina Assets) for the period of April 15, 2015 to December 31, 2015. For the year ended December 31, 2015, production includes 260 days for the Pembina Assets and 365 days for the original Bonterra assets.

(2) Represents the Acquisition that closed April 15, 2015 for $170,430,000.

(3) Annual figures for 2013 include the results of a corporate acquisition for the period of January 25, 2013 to December 31, 2013. For the year ended December 31, 2013, production includes 341 days for the corporate acquisition and 365 days for the original Bonterra assets.

(4) Represents a plan of arrangement, where Bonterra completed a corporate acquisition. The Company issued 10,711,405 common shares valued at $502,258,000 which included $10,000,000 of acquired cash.

(5) 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.

(6) 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

	2015			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2(1)	Q1
FINANCIAL				
Revenue – realized oil and gas sales	**44,678**	52,160	57,921	42,480
Funds flow(2)	**24,046**	28,754	43,058	22,090
Per share – basic	**0.71**	0.87	1.34	0.69
Per share – diluted	**0.71**	0.87	1.34	0.69
Payout ratio	**62%**	52%	34%	87%
Cash flow from operations	**27,808**	36,024	17,960	26,079
Per share – basic	**0.84**	1.09	0.56	0.81
Per share – diluted	**0.84**	1.09	0.56	0.81
Payout ratio	**56%**	41%	81%	74%
Cash dividends per share	**0.45**	0.45	0.45	0.60
Earnings (loss) before income taxes	**(5,223)**	746	8,676	(2,217)
Net earnings (loss)	**(4,113)**	(321)	(2,711)	(1,935)
Per share – basic	**(0.13)**	(0.01)	(0.08)	(0.06)
Per share – diluted	**(0.13)**	(0.01)	(0.08)	(0.06)
Capital expenditures and acquisitions, net of dispositions	**8,384**	14,402	167,182(3)	38,960(4)
Total assets	**1,183,593**	1,200,856	1,225,291	1,072,534
Working capital deficiency	**29,804**	29,080	27,558	37,633
Long-term debt	**332,471**	335,863	361,430	207,217
Shareholders' equity	**595,805**	610,793	599,911	613,886
OPERATIONS				
Oil – bbl per day	**8,424**	9,177	8,823	8,128
– average price ($ per bbl)	**49.50**	53.26	64.27	48.70
NGLs – bbl per day	**710**	753	677	791
– average price ($ per bbl)	**21.49**	18.05	21.35	22.36
Natural gas – mcf per day	**20,423**	19,191	19,452	19,709
– average price ($ per mcf)	**2.61**	3.36	2.83	2.97
Total barrels of oil equivalent (BOE) per day(5)	**12,538**	13,129	12,743	12,204

(1) Quarterly figures for Q2 2015 include the results of a purchase (the Acquisition) of primarily Pembina Cardium oil and gas assets (Pembina Assets) for the period of April 15, 2015 to December 31, 2015. Production includes 76 days for the Pembina Assets and 91 days for the original Bonterra assets.

(2) 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.

(3) Includes $153,230,000 (less a deposit of $17,200,000) for the Acquisition that closed on April 15, 2015 and capital expenditures of $13,952,000.

(4) Includes a deposit of $17,200,000 for the Acquisition and capital expenditures of $21,760,000.

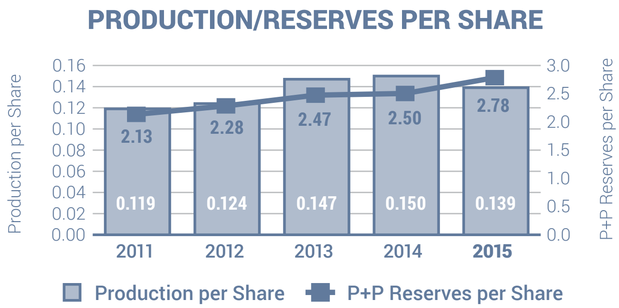
(5) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

MESSAGE TO SHAREHOLDERS

BONTERRA ENERGY CORP. (BONTERRA OR THE COMPANY) CONTINUED TO REALIZE FINANCIAL AND OPERATIONAL SUCCESS THROUGH 2015 DESPITE AN EXTREMELY CHALLENGING COMMODITY PRICE ENVIRONMENT. WHILE GLOBAL COMMODITY PRICES ARE OUT OF THE COMPANY'S CONTROL, BONTERRA CHOSE TO FOCUS ON FACTORS THAT IT IS ABLE TO MANAGE TO ENSURE FINANCIAL FLEXIBILITY, FUTURE GROWTH AND LONG-TERM CORPORATE SUSTAINABILITY.

Bonterra focused on several areas in 2015, including:

- **Cost Reductions:** Bonterra has always maintained a low cost structure, and was especially successful with cost reduction efforts in 2015. The all-in corporate costs of approximately Cdn$20.00 per BOE including royalties, operating expense (including transportation costs), administrative expense and interest on long-term debt is one of the lowest in the industry. This reflects a reduction in per BOE production costs by 14% and administrative costs by 32% from the same period one year ago. In 2016, Bonterra will seek further reductions in capital for drilling, completions and infrastructure costs, for operating costs and for general and administrative expenses.
- **Capital Efficiencies:** Bonterra successfully reduced per well capital costs by 27% in 2015, through a combination of pad drilling from sites with existing infrastructure, general service cost reductions, fewer drilling days per well and better efficiencies in the field. New drilling and completions practices were advanced as a result of the Company's work on optimal frac design and assessment of horizontal lateral lengths.
- **Managing Financial Flexibility:** Bonterra's current net debt is higher than previous years which is an area of concern for the Company. It is presently at approximately 3.1 to 1.0 times net debt to funds flow on a four quarter trailing basis, resulting from a strategic acquisition. The Company's goal is to reduce this ratio in the future to a range of 1.5 to 1.0 times when commodity prices have recovered or 2.5 to 1.0 times during periods when commodity prices remain low.
- **Access to Infrastructure:** The importance of consistent and reliable infrastructure was demonstrated during 2015 as Bonterra experienced production impacts caused by non-operated facility and transportation issues. Bonterra's firm service commitments have increased from 30% to 90% in 2015 and greatly improved its access to markets going forward.
- **Future Growth Potential:** Bonterra has one of the largest inventories of economic undrilled locations amongst its peer group with an estimated 20 years of undrilled locations in inventory. If commodity prices continue to be low and fewer wells are drilled annually, this economic undrilled location inventory increases to approximately 30 years, offering substantial future growth potential.
- **Conservative Business Approach:** The Company continues to be cautious and conservative regarding the determination of future reserves bookings. With only approximately 30% of its undrilled well locations included in the reserves evaluation, Bonterra has positioned the Company well to capture future upside.
- **Balance Sheet Protection:** Bonterra has a history of protecting long-term shareholder returns and demonstrated this again in 2015. In addition to cost reduction initiatives



"In 2015, Bonterra's proved plus probable reserves per share grew 11%, and its reserve life index was approximately 20 years."

in the current weak price environment, Bonterra also reduced the monthly dividend to balance spending with funds flow and to protect its balance sheet. This will ensure the Company can positively respond should there be a sustained improvement in commodity prices. With increased funds flow, the Company will increase the capital program, reduce debt, increase dividends or some combination thereof. This will continue to be analyzed on a month to month basis.

- **Maximizing Asset Value:** In 2015, Bonterra piloted its first waterfloods in two areas in Carnwood with two horizontal water injection wells. The waterfloods are still early-staged, but the initial results are encouraging. Future waterflood expansion may improve recoveries of the large amount of remaining oil in place in the Pembina Cardium field, resulting in greater long-term value creation for shareholders.

OUTLOOK

For 2016, Bonterra's initial capital expenditures budget is set at approximately $40 million but capital spending will be reviewed by the Company on a monthly basis. With this level of capital, Bonterra estimates 2016 production will average approximately 12,500 BOE per day. Further cost reductions and improved capital efficiencies through pad drilling and new completions technologies will be pursued. With a low corporate decline rate, minimal capital is required to hold production volumes flat and if needed, Bonterra can reduce capital further until prices improve. The large inventory of economic drill locations supports substantial production growth when commodity prices are high while still generating positive returns through periods of weak commodity prices.

Following its review of Alberta's royalty structure, the Alberta Provincial Government released its proposed Modernized Royalty Framework (MRF) on January 29, 2016, which is scheduled to take effect January 1, 2017. With limited details, the future impact of the review is presently impossible to assess. The Government and the resource industry are continuing to negotiate and further details are scheduled to be released by the end of March 2016. Until full details of the MRF are released, Bonterra cannot confirm what impact this will have on the Company. As more information becomes available, the Company will be able to better assess and provide details for its shareholders.

The Company will continue pursuing its sustainable growth strategy by minimizing the amount of debt and managing its dividend in a responsible manner. Bonterra will continue to focus on operational efficiencies, financial discipline, and optimal returns for shareholders, independent of the weaker commodity prices and provincial and federal political uncertainty. The future for Bonterra remains positive over the long term as the Company will continue to be conservatively managed to effectively withstand future challenging commodity price environments.

The Board of Directors wishes to thank the employees for their contribution and Bonterra's shareholders for their continued support during these very difficult times.

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

OPERATIONS

BONTERRA IS FOCUSED ON THE SUSTAINABLE DEVELOPMENT OF ITS ASSET BASE THROUGH A DISCIPLINED PACE OF DEVELOPMENT AND EFFICIENT OPERATING PRACTICES. THE COMPANY HAS A HIGH-QUALITY LAND BASE CONCENTRATED IN THE LARGE PEMBINA CARDIUM OIL POOL WITH YEARS OF DRILLING INVENTORY AND UPSIDE POTENTIAL. A LOW PRODUCTION DECLINE RATE AND CONSERVATIVE FINANCIAL MANAGEMENT SUPPORT BONTERRA'S ATTRACTIVE DIVIDEND-PLUS-GROWTH MODEL.

EFFICIENT

Bonterra drove down capital costs per well while improving recoveries through pad drilling, increased well spacing density and being a pioneer of a sliding sleeve completion technology across its Cardium acreage. A significant portion of the cost reductions are structural in nature, meaning Bonterra can continue to realize savings when commodity prices improve. Operating costs per BOE have also been reduced through a combination of field optimization and reductions in service company rates. Bonterra's firm transportation arrangements for natural gas increased to 90% commencing in late 2015 and provide more consistent access to markets and reduced production disruptions.

SUSTAINABLE

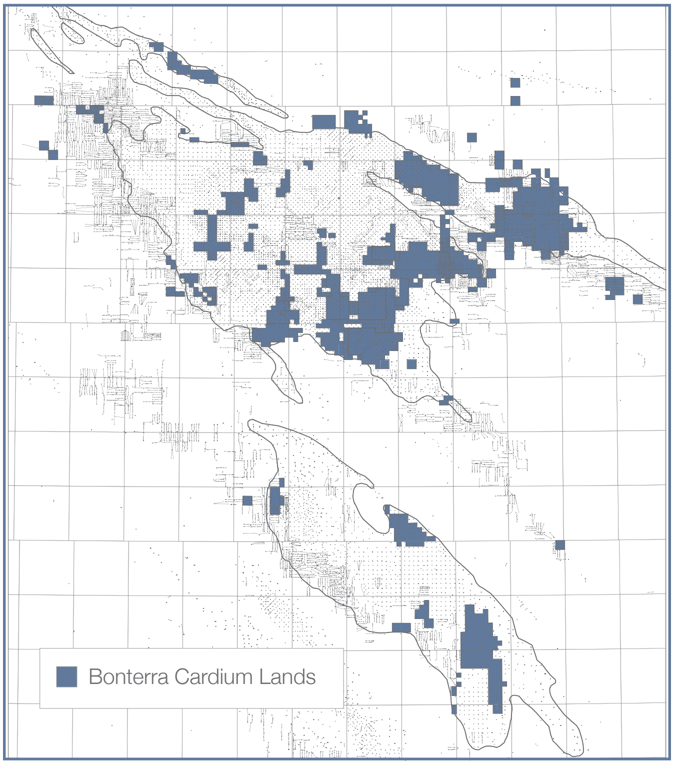
Bonterra's assets are concentrated in the Pembina Cardium pool in central Alberta, one of Canada's largest oil fields characterized by low-risk drilling opportunities, stable production rates and high-quality light oil. To date, less than 13% of the estimated 10.6 billion barrels of oil in place has been produced, which offers significant long-term development potential. The Company has a very low production decline rate and its conservative 2015 reserves booking does not fully reflect improvements in well performance from enhanced completions. Bonterra's low P+P Finding and Development (F&D) costs(1) of $3.12 per BOE generated a strong recycle ratio of 8.9 times. Bonterra's booked reserves currently represent only 30% of its internally estimated inventory of future undrilled locations supporting long-term sustainability.

DISCIPLINED

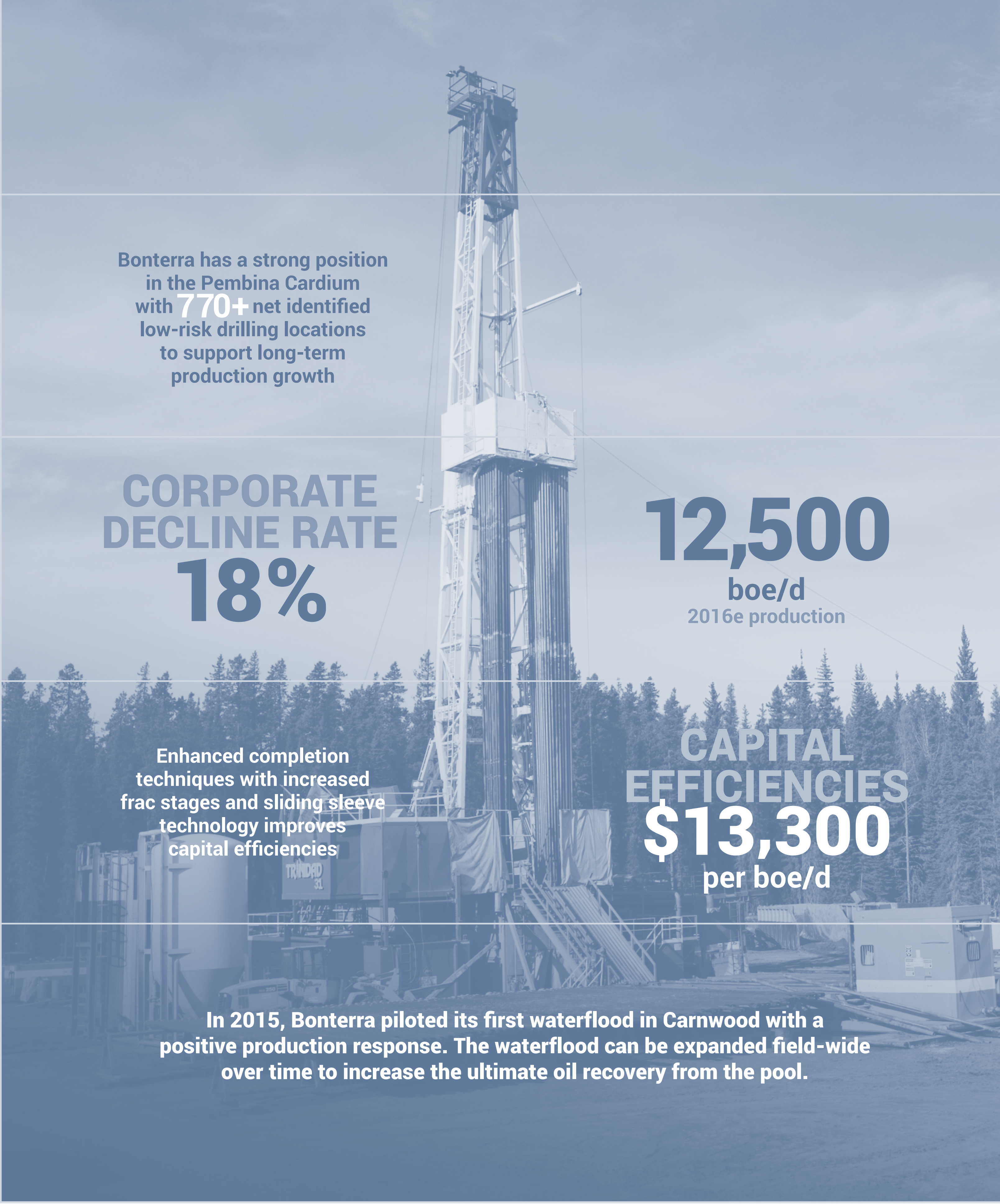
Exercising conservative financial management and preserving balance sheet strength remain key priorities in Bonterra's disciplined approach. With ongoing weakness in commodity prices, Bonterra continues to assess its results monthly and set the monthly dividend level based on the prior month's actual funds flow. This disciplined approach affords greater flexibility to adjust spending allocated to capital, dividends and debt reduction and enhances Bonterra's ability to deliver attractive returns to shareholders.

DRILLING ADVANCEMENTS

Bonterra continues to seek ways to add incremental production, including through the implementation of a waterflood program in Carnwood, as well as increasing drilling density to expand our inventory of future well locations. Bonterra has over 20 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 2015 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.



(1) Including change in future development capital.



Bonterra has a strong position in the Pembina Cardium with **770+** net identified low-risk drilling locations to support long-term production growth

CORPORATE DECLINE RATE

18%

12,500

boe/d

2016e production

Enhanced completion techniques with increased frac stages and sliding sleeve technology improves capital efficiencies

CAPITAL EFFICIENCIES

$13,300

per boe/d

In 2015, Bonterra piloted its first waterflood in Carnwood with a positive production response. The waterflood can be expanded field-wide over time to increase the ultimate oil recovery from the pool.

STATISTICAL REVIEW

SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2015

	Light & Medium Crude Oil	Associated & Non-Associated Gas	Natural Gas Liquids	Oil equivalent[4]	Future Development Capital
	(MBbl)	(MMcf)	(MBbl)	(MBOE)	(000s)
PROVED					
Developed Producing	26,276	57,900	2,693	38,619	$ -
Developed Non-producing	1,293	7,685	239	2,813	$ 2,219
Undeveloped	19,467	45,587	2,186	29,251	$ 495,571
TOTAL PROVED	47,036	111,172	5,118	70,683	$ 497,792
PROBABLE	12,522	34,957	1,590	19,938	$ 20,753
TOTAL PROVED + PROBABLE[1] [2] [3]	59,558	146,128	6,708	90,621	$ 518,544

(1) Reserves have been presented on gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company.
(2) Totals may not add due to rounding.
(3) Based on Sproule's December 31, 2015 escalated price deck.
(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2015[1] [2]

	Light & Medium Crude Oil		Associated & Non-Associated Gas		Natural Gas Liquids		Oil Equivalent	
	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable
	(MBbl)	(MBbl)	(MMcf)	(MMcf)	(MBbl)	(MBbl)	(MBOE)	(MBOE)
Opening Balance, December 31, 2014	40,529	51,719	108,128	138,887	4,245	5,381	62,795	80,248
Extensions & Improved Recovery[2]	1,480	1,864	3,171	4,012	123	156	2,132	2,688
Technical Revisions	215	(1,366)	3,989	1,341	640	763	1,520	(379)
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	8,665	11,186	9,077	11,988	565	749	10,743	13,934
Dispositions[4]	(119)	(150)	(176)	(220)	(6)	(8)	(154)	(194)
Economic Factors	(592)	(553)	(5,870)	(2,733)	(182)	(68)	(1,752)	(1,077)
Production	(3,142)	(3,142)	(7,146)	(7,146)	(266)	(266)	(4,599)	(4,599)
CLOSING BALANCE, DECEMBER 31, 2015	**47,036**	**59,558**	**111,172**	**146,128**	**5,118**	**6,708**	**70,684**	**90,621**

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.
(2) Increases to Extensions & Improved Recovery include infill drilling.
(3) Totals may not add due to rounding.
(4) Includes volumes associated with Farm outs.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2015

($M)	Net Present Value Before Income Taxes Discounted at (% per Year)			
Reserves Category	0%	5%	10%	15%
PROVED				
Developed Producing	1,444,628	960,825	713,773	567,804
Developed Non-producing	64,757	45,010	33,355	25,984
Undeveloped	815,905	472,671	295,647	192,317
TOTAL PROVED	2,325,289	1,478,506	1,042,775	786,105
PROBABLE	921,885	487,963	321,798	238,564
TOTAL PROVED + PROBABLE(1) (2) (3)	3,247,175	1,966,469	1,364,573	1,024,669

(1) Evaluated by Sproule as at December 31, 2015. Net present value of future net revenue does not represent fair value of the reserves.

(2) Net present values equals net present value before income taxes based on Sproule's forecast prices and costs as of December 31, 2015. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material.

(3) Includes abandonment and reclamation costs as defined in NI 51-101.

FINDING, DEVELOPMENT & ACQUISITION (FD&A) AND FINDING & DEVELOPMENT (F&D) COSTS

	Proved Reserve Net Additions				Proved + Probable Reserve Net Additions			
	2015	2014	2013	3 Yr Avg(4)	2015	2014	2013	3 Yr Avg(4)
FD&A COSTS PER BOE(1) (2) (3)								
Including FDC	$ 11.52	$ 18.90	$ 24.80	$ 20.02	$ 11.60	$ 22.67	$ 21.06	$ 18.95
Excluding FDC	$ 15.50	$ 11.57	$ 23.63	$ 18.48	$ 15.29	$ 15.54	$ 20.12	$ 18.13
F&D COSTS PER BOE(1) (2) (3)								
Including FDC	$ 4.76	$ 18.89	$ 21.38	$ 18.57	$ 3.12	$ 22.71	$ 18.63	$ 19.92
Excluding FDC	$ 33.26	$ 11.53	$ 17.10	$ 14.99	$ 56.32	$ 15.53	$ 14.66	$ 17.37

(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 and F&D costs are net of proceeds of disposal 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 + Probable reserves on a weighted average basis.

COMMODITY PRICES USED IN THE ABOVE CALCULATIONS OF RESERVES ARE AS FOLLOWS:

	Edmonton Par Price	Natural Gas AECO-C Spot	Butanes Edmonton	Pentanes Edmonton	Operating Cost Inflation Rate	Exchange Rate
	($Cdn per bbl)	($Cdn per mmbtu)	($Cdn per bbl)	($Cdn per bbl)	(% per Yr)	($US/$Cdn)
FORECAST						
2016	55.20	2.25	39.09	59.10	0.0	0.750
2017	69.00	2.95	51.43	73.88	0.0	0.800
2018	78.43	3.42	58.46	83.98	1.5	0.830
2019	89.41	3.91	66.64	95.73	1.5	0.850
2020	91.71	4.20	68.35	98.19	1.5	0.850
2021	93.08	4.28	69.38	99.66	1.5	0.850

PRODUCTION

	2015		
	OILS & NGLS (BBL PER DAY)	**NATURAL GAS (MCF PER DAY)**	**TOTAL (BOE PER DAY)**
Alberta	**9,244**	**19,013**	**12,413**
Saskatchewan	**120**	**184**	**150**
British Columbia	**10**	**498**	**93**
	9,374	**19,694**	**12,656**

LAND HOLDINGS

	2015		2014	
	GROSS ACRES	**NET ACRES**	Gross Acres	Net Acres
Alberta	**296,684**	**179,503**	245,263	150,835
Saskatchewan	**8,891**	**6,200**	9,576	6,509
British Columbia	**62,045**	**22,639**	62,045	22,639
	367,620	**208,342**	316,884	179,983

PETROLEUM AND NATURAL GAS EXPENDITURES

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, and exploration and development costs for the years ended December 31:

($ 000s)	**2015**	2014
Land	**479**	402
Acquisitions	**170,430**	-
Dispositions	**-**	(1,152)
Exploration and development costs	**58,019**	155,262
Net petroleum and natural gas capital expenditures	**228,928**	154,512

DRILLING HISTORY

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

	2015					
	DEVELOPMENT		**EXPLORATORY**		**TOTAL**	
	GROSS	**NET**	**GROSS**	**NET**	**GROSS**	**NET**
Crude oil	**26.0**	**17.5**	**-**	**-**	**26.0**	**17.5**
Natural gas	**-**	**-**	**-**	**-**	**-**	**-**
Total	**26.0**	**17.5**	**-**	**-**	**26.0**	**17.5**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	2014					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	65.0	47.5	-	-	65.0	47.5
Natural gas	-	-	-	-	-	-
Total	65.0	47.5	-	-	65.0	47.5
Success rate	100%	100%	-	-	100%	100%

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated March 17, 2016 is a review of the operations and current financial position for the year ended December 31, 2015 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, 2015**(1)	December 31, 2014	December 31, 2013(3)
FINANCIAL				
Revenue – realized oil and gas sales		**197,239**	339,694	295,675
Cash flow from operations		**107,871**	222,353	173,896
Per share – basic		**3.30**	6.97	5.76
Per share – diluted		**3.30**	6.94	5.74
Payout ratio		**59%**	51%	58%
Cash dividends per share		**1.95**	3.54	3.33
Net earnings (loss)		**(9,080)**	38,761	62,758
Per share – basic		**(0.28)**	1.21	2.08
Per share – diluted		**(0.28)**	1.21	2.07
Capital expenditures and acquisitions, net of dispositions		**228,928**(2)	155,565	621,485(4)
Total assets		**1,183,593**	1,042,938	1,000,531
Working capital deficiency		**29,804**	53,642	35,985
Long-term debt		**332,471**	154,723	156,764
Shareholders' equity		**595,805**	635,198	667,641
OPERATIONS				
Oil	– barrels per day	**8,641**	8,582	7,787
	– average price ($ per barrel)	**54.08**	90.61	89.26
NGLs	– barrels per day	**733**	807	744
	– average price ($ per barrel)	**20.80**	52.26	52.41
Natural gas	– MCF per day	**19,694**	22,833	21,954
	– average price ($ per MCF)	**2.94**	4.86	3.46
Total barrels of oil equivalent per day (BOE)		**12,656**	13,195	12,190

(1) Annual figures for 2015 include the results of a purchase (the Acquisition) of primarily Pembina Cardium oil and gas assets (Pembina Assets) for the period of April 15, 2015 to December 31, 2015. Production includes 260 days for the Pembina Assets and 365 days for the original Bonterra assets.

(2) Represents the Acquisition that closed April 15, 2015 for $170,430,000.

(3) Annual figures for 2013 include the results of an acquired corporation (the Corporation), for the period of January 25, 2013 to December 31, 2013. Production includes 341 days for the Corporation and 365 days for the original Bonterra assets.

(4) Includes the acquisition of the Corporation, through a plan of arrangement that closed on January 25, 2013. The Company issued 10,711,405 common shares valued at $502,258,000 which included $10,000,000 of acquired cash. Capital expenditures, net of dispositions were $119,227,000 excluding the acquisition.

QUARTERLY COMPARISONS

	2015			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2[1]	Q1
FINANCIAL				
Revenue – oil and gas sales	**44,678**	52,160	57,921	42,480
Cash flow from operations	**27,808**	36,024	17,960	26,079
Per share – basic	**0.84**	1.09	0.56	0.81
Per share – diluted	**0.84**	1.09	0.56	0.81
Payout ratio	**54%**	41%	81%	74%
Cash dividends per share	**0.45**	0.45	0.45	0.60
Net earnings (loss)	**(4,113)**	(321)	(2,711)	(1,935)
Per share – basic	**(0.13)**	(0.01)	(0.08)	(0.06)
Per share – diluted	**(0.13)**	(0.01)	(0.08)	(0.06)
Capital expenditures and acquisitions, net of dispositions	**8,384**	14,402	167,182[2]	38,960[3]
Total assets	**1,183,593**	1,200,856	1,225,291	1,072,534
Working capital deficiency	**29,804**	29,080	27,558	37,633
Long-term debt	**332,471**	335,863	361,430	207,217
Shareholders' equity	**595,805**	610,793	599,911	613,886
OPERATIONS				
Oil (barrels per day)	**8,424**	9,177	8,823	8,128
NGLs (barrels per day)	**710**	753	677	791
Natural gas (MCF per day)	**20,423**	19,191	19,452	19,709
Total BOE per day	**12,538**	13,129	12,743	12,204

(1) Quarterly figures for Q2 2015 include the results of the Pembina Assets, for the period of April 15, 2015 to June 30, 2015. Production includes 76 days for the acquired Pembina Assets and 91 days for the original Bonterra assets.

(2) Includes $153,230,000 (less a deposit of $17,200,000) for the Acquisition that closed on April 15, 2015 and capital expenditures of $13,952,000.

(3) Includes a deposit of $17,200,000 for the Acquisition and capital expenditures of $21,760,000.

	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	(32,877)[4]	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 (barrels per day)	8,762	8,874	9,109	7,567
NGLs (barrels 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

(4) 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 Canada Revenue Agency.

BUSINESS ENVIRONMENT AND SENSITIVITIES

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials and foreign exchange. 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.

	Q4-2015	Q3-2015	Q2-2015	Q1-2015	Q4-2014	Q3-2014	Q2-2014	Q1-2014
Crude oil WTI ($US per bbl)	**42.18**	46.43	57.94	48.63	73.15	97.17	102.99	98.68
WTI to MSW Stream Index Differential ($US per bbl)(1)	**(2.51)**	(3.45)	(2.93)	(6.93)	(6.46)	(7.93)	(6.14)	(8.25)
Foreign exchange $US to $Cdn	**1.3353**	1.3094	1.2294	1.2411	1.1357	1.0893	1.0905	1.1035
Bonterra average realized oil price ($Cdn per bbl)	**49.50**	53.26	64.27	48.70	71.37	92.73	102.36	96.53
Natural gas AECO ($Cdn per mcf)	**2.45**	2.89	2.64	2.74	3.58	4.00	4.67	5.69
Bonterra average realized gas price ($Cdn per mcf)	**2.61**	3.36	2.83	2.97	3.92	4.54	4.85	6.16

(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;
- Geo-political events that affect worldwide crude oil production;
- The reduced value of the Canadian dollar compared to the US dollar continues to positively affect Bonterra's realized prices;
- Whether there is sufficient or new take-away capacity to transport energy commodities;
- Weather dependence; the warm winter across North America has created a larger imbalance of the increased gas and distillate (such as heating oil) production to demand; and
- Timing of plant and refinery turnarounds.

In January 2016, WTI decreased to just over $30 US per bbl and has dropped under $30 US per bbl in February primarily due to the worldwide crude oil supply and demand imbalance partially driven by continued global production gains and high inventories that are delaying the effect of any supply/demand rebalancing. It is difficult to predict future pricing, but the Company expects crude oil prices to remain low for the remainder of 2016.

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 2016(1)

Impact on cash flow	Change ($)	$000s	$ per share(2)
Realized crude oil price ($ per bbl)	1.00	2,931	0.09
Realized natural gas price ($ per mcf)	0.10	681	0.02
$US to $Cdn exchange rate	0.01	1,344	0.04

(1) This analysis uses current royalty rates, annualized estimated average production of 12,500 BOE per day and no changes in working capital.
(2) Based on annualized basic weighted average shares outstanding of 33,143,435.

BUSINESS OVERVIEW, STRATEGY AND KEY PERFORMANCE DRIVERS

Bonterra is an oil and gas company that is primarily focused on the development of its Cardium land within the Pembina and Willesden Green areas located in central Alberta. The Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original oil in place with very low recoveries. Horizontal drilling with multi stage fracking drastically improves recoveries from areas developed with vertical drilling and extends the economic edge of the reservoir where vertical drilling is not economic. Bonterra operates 89 percent of its production with an average land working interest of 76 percent. At December 31, 2015, Bonterra had a horizontal drilling inventory of approximately 773 net locations.

Even with the significant reduction in commodity prices in comparison to 2014, the Company has been able to generate positive cash flow on an annual basis. Bonterra was able to reduce capital costs by 27 percent on a per well basis, production costs by 14 percent on a per BOE basis and general and administrative costs by 32 percent from the same period a year ago. The reductions were achieved through a combination of innovation, optimization, service cost reduction and a reduction of overall compensation. In further response to the continued volatile pricing environment for commodities and to maintain cash flow sustainability, the Company reduced the monthly dividend from $0.15 per share to $0.10 per share commencing with the January 2016 dividend. Should commodity prices improve, the Company also has flexibility to manage capital costs related to undrilled locations by allowing for accelerated development.

On April 15, 2015, the Company acquired 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, 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 $170,430,000. If Bonterra had closed the Acquisition on January 1, 2015, the Pembina Assets would have added approximately 1,700 BOE per day of production, oil and gas sales of approximately $29,098,000, royalty expenses of approximately $971,000 and operating expenses of approximately $14,761,000 for the year ended December 31, 2015. The combined production for the Company for the year would have been 13,147 BOE per day. The actual amounts recorded for the Pembina Assets include oil and gas sales of $21,260,000, royalty expenses of $593,000 and operating expenses of $10,448,000 for the period from April 15, 2015 to December 31, 2015. The Pembina Assets are approximately 87 percent oil and NGL weighted with a low decline rate of seven percent. These assets also include 136 net future potential drilling locations and supporting infrastructure. For more information about the Acquisition, refer to Note 5 of the December 31, 2015 audited financial statements.

During 2015, Bonterra spent approximately $58,498,000 on its capital program and drilled 20 gross (16.7 net) operated wells and completed and tied-in 24 gross (22.2 net) wells (of which 10 wells were drilled in 2014, but not completed until 2015). Of the 20 operated wells drilled 6 (4.5 net) were completed and tied-in in the first quarter of 2016. In addition, 6 (0.8 net) non-operated wells were drilled and placed on production during 2015. The Company also added field compression to redirect gas production in the Carnwood area to two of its wholly owned plants in the Keystone Area. In December 2015, the Company set its capital expenditure budget for 2016 at approximately $40 million. With continued price erosion for oil in 2016, the Company continues to review capital spending on a month by month basis.

The Company averaged production of 12,656 BOE per day for the full year of 2015, which was between the annual guidance of 12,600 to 12,900 BOE per day. During 2015 production was reduced by approximately 1,100 BOE per day from oil apportionments, gas capacity restrictions and voluntarily shutting-in uneconomic production due to low commodity prices.

During 2015, the Company increased its natural gas firm service delivery with TransCanada Pipeline from under 7,000 mcf per day to over 19,000 mcf per day. Considering approximately 90 percent of Bonterra's current natural gas production is from solution gas, this will reduce transportation curtailments associated with interruptible service, thereby decreasing the restrictions on oil production. The Company has also reactivated some of its restricted production as a result of redirecting solution gas to alternative gas plants. To further alleviate future potential gas capacity issues, in the fourth quarter of 2015, Bonterra took over operatorship of a third gas plant in the Pembina Cardium area that it has ownership in. The ability to redirect gas to operated facilities should further reduce a portion of the shut-in issues experienced during the 2015 year while lowering gas processing costs. The Company is estimating that its average annual production for 2016 will be approximately 12,500 BOE per day, but it will be continuously adjusting annual production targets according to changing commodity prices and capital spending program.

Bonterra's successful operations are dependent upon several factors, including but not limited to, commodity prices, efficiently managing capital spending, monthly dividends, 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, 2015		September 30, 2015		December 31, 2014		**DECEMBER 31, 2015**		December 31, 2014	
	GROSS[1]	**NET[2]**	Gross[1]	Net[2]	Gross[1]	Net[2]	**GROSS[1]**	**NET[2]**	Gross[1]	Net[2]
Crude oil horizontal – operated	**3**	**1.5**	6	5.9	10	9.9	**20**	**16.7**	43	42.6
Crude oil horizontal – non-operated	**3**	**0.4**	2	0.3	-	-	**6**	**0.8**	22	4.9
Total	**6**	**1.9**	8	6.2	10	9.9	**26**	**17.5**	65	47.5
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 2015, the Company placed 10 gross (9.9 net) wells on production that were drilled in the later part of 2014. In addition, the Company drilled 20 gross (16.7 net) wells, of which 14 gross (12.3 net) were placed on production in 2015 with the remaining six wells scheduled to be on production in the first quarter of 2016. As well, six gross (0.8 net) non-operated wells were drilled and placed on production during the year.

PRODUCTION

	Three months ended			Year ended	
	DECEMBER 31, 2015	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Crude oil (barrels per day)	**8,424**	9,177	8,762	**8,641**	8,582
NGLs (barrels per day)	**710**	753	911	**733**	807
Natural gas (MCF per day)	**20,423**	19,191	22,883	**19,694**	22,833
Average BOE per day	**12,538**	13,129	13,488	**12,656**	13,195

Production volumes during 2015 decreased to 12,656 BOE per day compared to 13,195 BOE per day in 2014. The decrease in production is primarily due to a significant reduction in development capital spending as Bonterra drilled 17.5 net wells in 2015 versus 47.5 net wells in 2014. In addition to a reduction of capital spending caused by low commodity prices, the Company also voluntarily shut-in approximately 510 BOE per day until commodity prices improve. A further 590 BOE per day of production was also shut-in due to non-operated facility turnarounds, oil apportionments, gas capacity restrictions imposed by TransCanada Pipelines and further restrictions for a downstream non-operated meter station expansion.

The decrease in production from a year ago was partially offset by an average of 1,700 BOE per day from the Pembina Assets, since the acquisition date of April 15, 2015.

Quarter over quarter, production volumes decreased by 591 BOE per day primarily due to 700 BOE per day of production being voluntarily shut-in due to low commodity prices and a further 320 BOE per day being shut in due to non-operated facility restrictions. This was partially offset by six gross (3.4 net) new wells being placed on production in November of 2015.

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, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Production volumes (BOE)	**1,153,476**	1,207,856	1,240,864	**4,619,277**	4,816,030
Gross production revenue	**$ 38.73**	$ 43.18	$ 55.56	**$ 42.70**	$ 70.53
Royalties	**(2.55)**	(3.06)	(5.87)	**(2.89)**	(7.91)
Production costs	**(11.81)**	(12.06)	(12.50)	**(11.95)**	(13.89)
Field netback	**$ 24.37**	$ 28.06	$ 37.19	**$ 27.86**	$ 48.73
General and administrative	**(1.63)**	(1.59)	(1.83)	**(1.56)**	(2.22)
Interest and other	**(2.98)**	(2.63)	(1.16)	**(2.60)**	(1.12)
Cash netback	**$ 19.76**	$ 23.84	$ 34.20	**$ 23.70**	$ 45.39

Cash netbacks have decreased in 2015 compared to 2014 primarily due to lower commodity prices and an increase in interest expense from funding the Pembina Assets with debt, which was partially offset by lower royalties, production costs and general and administration costs. Quarter over quarter cash netbacks decreased mainly due to lower crude oil and natural gas prices.

OIL AND GAS SALES

	Three months ended			Year ended	
	DECEMBER 31, 2015	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Revenue – oil and gas sales ($ 000s)	**44,678**	52,160	68,940	**197,239**	339,694
Average Realized Prices:					
Crude oil ($ per barrel)	**49.50**	53.26	71.37	**54.08**	90.61
NGLs ($ per barrel)	**21.49**	18.05	37.49	**20.80**	52.26
Natural gas ($ per MCF)	**2.61**	3.36	3.92	**2.94**	4.86
Average ($ per BOE)	**38.73**	43.18	55.56	**42.70**	70.53

Revenue from oil and gas sales decreased by $142,455,000 in 2015 or 42 percent compared to 2014. This decrease was primarily due to a 39 percent decrease in commodity prices on a per BOE basis.

The quarter over quarter decrease in oil and gas sales of $7,482,000 or 14 percent was primarily due to decreased crude oil and natural gas prices.

The Company's product split on a revenue basis for 2015 is approximately 89 percent weighted towards crude oil and NGLs.

ROYALTIES

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Crown royalties	**1,901**	2,398	5,021	**8,007**	23,779
Freehold, gross overriding and other royalties	**1,039**	1,301	2,259	**5,354**	14,331
Total royalties	**2,940**	3,699	7,280	**13,361**	38,110
Crown royalties – percentage of revenue	**4.3**	4.6	7.3	**4.1**	7.0
Freehold, gross overriding and other royalties – percentage of revenue	**2.3**	2.5	3.3	**2.7**	4.2
Royalties – percentage of revenue	**6.6**	7.1	10.6	**6.8**	11.2
Royalties $ per BOE	**2.55**	3.06	5.87	**2.89**	7.91

Royalties paid by the Company consist of crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia and non-crown royalties. Royalties on a per BOE basis decreased by $5.02 per BOE for 2015 compared to 2014, primarily due to lower commodity prices. On a percentage of revenue basis royalty rates decreased due to lower crown royalty rates as a result of decreased commodity prices and less production from freehold properties, which are generally subject to higher royalty rates compared to crown royalty rates.

Quarter over quarter royalties, on a per BOE basis, decreased primarily due to a decrease in crude oil and natural gas prices realized in the fourth quarter.

In 2016, the provincial government of Alberta announced the key highlights of a proposed Modernized Royalty Framework (MRF) that will be effective on January 1, 2017. These highlights include providing royalty incentives for the efficient development of conventional crude oil, natural gas, and NGL resources, no changes to the royalty structure of wells drilled prior to 2017 for a 10 year period from the royalty program's implementation date, the replacement of royalty credits or holidays on conventional wells by a revenue minus cost framework with a post-revenue minus cost royalty rate based on commodity prices, the reduction of royalty rates for mature wells, and a neutral internal rate of return for any given play compared to the current royalty framework. Since the provincial government of Alberta has not yet released all of the details of the MRF, the Company cannot determine if the MRF will have a material impact on Bonterra's results of operations on a go forward basis.

Bonterra will evaluate the impact of the MRF on the Company's expected results of operations and cash flows as more details are released.

PRODUCTION COSTS

	Three months ended			Year ended	
($ 000s except $ per BOE)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Production costs(1)	**13,622**	14,570	15,516	**55,215**	66,878
$ per BOE	**11.81**	12.06	12.50	**11.95**	13.89

(1) Transportation costs are included in production costs.

Production costs on a per BOE basis for 2015 decreased 14 percent compared to 2014. Production costs on a BOE basis have primarily decreased as a result of field optimizations leading to reduced well maintenance, more efficient produced water handling and decreased chemical costs. Also production costs decreased due to a reduction in rates charged by service companies and lower freehold mineral taxes due to lower commodity prices. These savings were partially offset by the production costs of the Pembina Assets that currently have higher operating costs due to the low production from individual vertical wells and a waterflood program. The higher costs per BOE in this area are expected to drop further as Bonterra gains efficiencies from reduced trucking, waterflood support, lower labour costs and more importantly through horizontal development adding new production in the area from its undrilled locations.

Quarter over quarter, production costs on a per BOE basis decreased primarily due to delaying well maintenance costs on marginal wells in the fourth quarter because of reduced commodity prices, compared to facility maintenance and plant turnarounds that generally occur in the third quarter.

OTHER INCOME

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Investment income	**41**	45	12	**251**	56
Administrative income	**15**	16	22	**77**	282
Gain on sale of properties	**-**	-	-	**-**	671
Realized gain on investments	**-**	-	-	**-**	1,102
	56	61	34	**328**	2,111

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 $9,538,000 at December 31, 2015 (December 31, 2014 – $7,966,000). The carrying value increased due to the $12,221,000 of investments purchased by the Company during 2015 which was partially offset by a decrease in market value of $2,519,000 through other comprehensive loss and investments sold in the year for proceeds of $8,130,000. This disposition resulted in a gain on sale of $1,191,000 which was recorded as an equity transfer between accumulated other comprehensive income and retained earnings and not recorded in profit and loss. The accounting treatment resulted from early adopting IFRS 9 "Financial Instruments" (see Financial Reporting Update).

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

GENERAL AND ADMINISTRATION (G&A) EXPENSE

	Three months ended			Year ended	
($ 000s except $ per BOE)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Employee compensation expense	**1,211**	912	1,399	**3,905**	7,111
Office and administration expense	**666**	1,007	877	**3,302**	3,559
Total G&A expense	**1,877**	1,919	2,276	**7,207**	10,670
$ per BOE	**1.63**	1.59	1.83	**1.56**	2.22

The decrease in employee compensation expense of $3,206,000 for 2015 compared to 2014 is primarily due to a decrease in accrued bonuses that resulted from lower net earnings before income taxes. 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.

Office and administration expense for 2015 decreased compared to 2014 due to a decrease in office rent, professional fees and a decrease in the allowance for doubtful accounts. The decrease quarter over quarter relates primarily to a decrease in the allowance for doubtful accounts and continuous disclosure costs.

FINANCE COSTS

	Three months ended			Year ended	
($ 000s except $ per BOE)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Interest on long-term debt	**3,244**	2,948	1,220	**10,390**	4,282
Other interest	**252**	291	251	**1,931**	1,461
Interest expense	**3,496**	3,239	1,471	**12,321**	5,743
$ per BOE	**3.03**	2.68	1.19	**2.67**	1.19
Unwinding of the discounted value of decommissioning liabilities	**514**	504	388	**1,878**	1,361
Total finance costs	**4,010**	3,743	1,859	**14,199**	7,104

Interest on long-term debt increased $6,108,000 in 2015 compared to 2014 as the Company increased the outstanding bank debt by $170,000,000 to finance the Pembina Asset acquisition in the second quarter. The Company's bank interest rate increased in the second half of 2015 due to a higher 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 a related party (see related party transactions) and a $25,000,000 subordinated promissory note from a private investor and a one-time interest charge of $694,000 paid to the vendor for the Pembina Asset acquisition for the period January 1, 2015 to April 15, 2015. Subsequent to the year ended December 31, 2015, the Company repaid $10,000,000 of the subordinated promissory note.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,515,000.

SHARE-OPTION COMPENSATION

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Share-option compensation	**1,550**	958	947	**4,270**	2,725

Share-option compensation is 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-option compensation increased by $1,545,000 from the same period a year ago due to less share-option compensation being amortized in 2014 as fewer options were outstanding during the year. Also, the fair value of the 1,772,500 options granted during the year (2014 – 1,769,000) increased from $2.82 per option to $3.68 per option due to an increase in volatility of the Company's share price used in valuing the options under the Black-Scholes option pricing model. Quarter over quarter share-option compensation increased due to the Company granting 807,000 stock options in the fourth quarter.

Based on the outstanding options as of December 31, 2015, the Company has an unamortized expense of $4,644,000, of which $4,153,000 will be recorded for 2016, $487,000 for 2017 and $4,000 for 2018. For more information about options issued and outstanding, refer to Note 17 of the December 31, 2015 audited annual financial statements.

DEPLETION AND DEPRECIATION, EXPLORATION AND EVALUATION AND GOODWILL

	Three months ended			Year ended	
($ 000s)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Depletion and depreciation	**25,775**	26,586	26,975	**101,150**	106,697
Exploration and evaluation	**183**	-	-	**183**	28

Provision for depletion and depreciation decreased by $5,547,000 for 2015 compared to 2014. The decrease in depletion and depreciation is primarily due to a decrease in production volumes and a lower decline rate associated with the acquired Pembina Assets. The quarter over quarter decrease in the provision was primarily due to a decrease in production volumes and less capital spent in the fourth quarter.

Exploration and evaluation expense related to expired leases.

There were no impairment provisions recorded for the years ended December 31, 2015 or 2014.

TAXES

Applying the statute income tax rate of 26.01 percent in effect for the 2015 year, the expected income tax provision would have been $515,000 on net earnings before income taxes. The higher than expected income tax provision of $11,062,000 for the 2015 year is primarily due to the Alberta provincial tax rate increasing to 12 percent from 10 percent that came into effect July 1, 2015, which increased the Company's deferred tax liability by approximately $8,490,000, resulting in a net loss.

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 (loss). The large tax expense of $70,832,000 for the 2014 fiscal year is related to a reduction in the Company's tax assets as a result of an agreement with CRA and an increase in earnings before income taxes. The reduction in tax assets was charged to deferred tax expense in the statement of comprehensive income (loss). In 2014, the Company utilized $6,645,000 of the federal investment tax credit receivable to reduce current taxes payable to $3,860,000. No taxes are owing for the 2015 fiscal year.

For additional information regarding income taxes, see Note 16 of the December 31, 2015 annual audited financial statements.

NET EARNINGS (LOSS)

	Three months ended			Year ended	
($ 000s except $ per share)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Net earnings (loss)	**(4,113)**	(321)	(32,877)	**(9,080)**	38,761
$ per share – basic	**(0.13)**	(0.01)	(1.04)	**(0.28)**	1.21
$ per share – diluted	**(0.13)**	(0.01)	(1.03)	**(0.28)**	1.21

Net earnings in 2015 decreased by $47,841,000 compared to the same period in 2014. Decreased net earnings resulted primarily from lower commodity prices, which was partially offset by a decrease in deferred income tax expense, royalties, production and G&A costs. The Company had net earnings before income taxes of $1,982,000 in a low price commodity environment.

The quarter over quarter increase in net loss was mainly due to lower crude oil and natural gas prices.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive loss for 2015 consists of an unrealized loss before tax on investments (including investment in a related party) of $2,519,000 relating to a decrease in the investments' fair value (December 31, 2014 – unrealized gain of $1,174,000). Realized gains decrease accumulated other comprehensive income as these gains are transferred to retained 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

	Three months ended			Year ended	
($ 000s except $ per share)	**DECEMBER 31, 2015**	September 30, 2015	December 31, 2014	**DECEMBER 31, 2015**	December 31, 2014
Cash flow from operations	**27,808**	36,024	50,465	**107,871**	222,353
$ per share – basic	**0.84**	1.09	1.57	**3.30**	6.97
$ per share – diluted	**0.84**	1.09	1.57	**3.30**	6.94

In 2015, cash flow from operations decreased by $114,482,000 compared to the same period a year ago. This was primarily due to a decrease in revenue from oil and gas sales, which were partially offset by a decrease in royalties, production and G&A costs. The quarter over quarter decrease of $8,216,000 was primarily due to a decrease in oil and gas sales due to lower crude oil and natural gas prices.

RELATED PARTY TRANSACTIONS

Bonterra holds 1,034,523 (December 31, 2014 – 1,034,523) common shares in Pine Cliff Energy Ltd (Pine Cliff) which represents less than one percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares had a fair market value as of December 31, 2015 of $962,000 (December 31, 2014 of $1,738,000). Pine Cliff paid a management fee to the Company of $60,000 (December 31, 2014 – $60,000) plus the reimbursement of certain administrative expenses. 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, 2015, the Company had an account receivable from Pine Cliff of $293,000 (December 31, 2014 – $316,000).

As at December 31, 2015, the Company's CEO, Chairman of the Board and major shareholder loaned the Company $12,000,000 (December 31, 2014 – $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 2015 was $261,000 (December 31, 2014 – $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 FROM OPERATIONS

Bonterra continues to focus on monitoring and managing its cash flow, capital expenditures and dividend payments. The Company did not 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 and as of December 31, 2015 had a ratio of 3.4 to 1 times. The increase in net debt to cash flow is primarily due to the Pembina Asset acquisition on April 15, 2015 and low commodity prices realized in 2015 compared to 2014. To manage its bank debt, Bonterra significantly reduced planned capital expenditures for 2015 compared to 2014 and reduced the monthly dividend payments by 50 percent beginning with the February 2015 payment. Beginning in January 2016, the Company further reduced the monthly dividend by $0.05 to $0.10 per common share. In addition the Company raised equity by way of a private placement of approximately $31 million. With the current oil commodity price environment the Company will be assessing its monthly dividend and capital expenditures for 2016 on a month to month basis.

WORKING CAPITAL DEFICIENCY AND NET DEBT

($ 000s)	**DECEMBER 31, 2015**	December 31, 2014
Working capital deficiency	**29,807**	53,642
Long-term bank debt	**332,471**	154,723
Net debt	**362,278**	208,365

The Company has sufficient availability on its credit facility to repay both the related party loan and the subordinated promissory note if required. The Company manages the working capital position during each quarter by monitoring capital spending and dividends paid compared to cash flow from operations.

Net debt is a combination of long-term bank debt and working capital. Net debt increased compared to the 2014 year. This was primarily attributable to decreased cash flow from lower field netbacks and the acquisition of the Pembina Assets, partially offset by decreased capital spending and reducing the monthly dividend from $0.30 per share to $0.15 per share that commenced with the February 2015 dividend. Beginning with the January 2016 dividend payment the Company further reduced the monthly dividend to $0.10 per share due to further declines in commodity prices.

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. Included in the working capital deficiency at December 31, 2015 is $37 million of debt relating to the subordinated promissory note and the amount due to related party. The Company has sufficient room on its credit facility to repay these loans if required.

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

CAPITAL EXPENDITURES

During the year ended December 31, 2015, the Company incurred development capital costs of $58,498,000 (December 31, 2014 – $155,566,000) net of proceeds on disposal of property, plant and equipment. The costs relate primarily to the drilling of 20 gross (16.7 net) Cardium operated horizontal wells, completing and tying-in 10 gross (9.9 net) Cardium operated wells that were drilled in 2014, and upgrading facilities and gathering systems. The Company also incurred $170,430,000 in capital costs for the Pembina Asset acquisition.

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 audited annual financial statements. As of December 31, 2015, the Company has bank facilities consisting of a $375,000,000 (December 31, 2014 – $220,000,000) syndicated revolving credit facility and a $50,000,000 (December 31, 2014 – $30,000,000) non-syndicated revolving credit facility. Amounts drawn under these credit facilities at December 31, 2015 totaled $332,471,000 (December 31, 2014 – $154,723,000). The interest rates on the outstanding debt as of December 31, 2015 were 4.95 percent and 4.38 percent on the Company's Canadian prime rate loan and Banker's Acceptances, respectively. The loan is revolving to April 29, 2016 with a maturity date of April 30, 2017 and is subject to annual review. The 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 14 of the December 31, 2015 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, 2015		December 31, 2014	
Issued and fully paid – common shares	**NUMBER**	**AMOUNT ($ 000S)**	Number	Amount ($ 000s)
Balance, beginning of year	**32,169,623**	**728,934**	31,322,171	685,898
Share issuance, private placement	**973,812**	**31,162**	-	-
Share issue costs, net of tax		**(76)**		-
Issued pursuant to the Company's share option plan	**-**	**-**	829,452	37,911
Transfer from contributed surplus to share capital		**-**		4,021
Shares issued for oil and gas properties	**-**	**-**	18,000	1,104
Balance, end of year	**33,143,435**	**760,020**	32,169,623	728,934

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 3,314,344 (December 31, 2014 – 3,216,962) 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 17 of the December 31, 2015 audited annual financial statements.

On July 8, 2015, the Company closed a private placement of 973,812 common shares to existing shareholders at a price of $32.00 per share, for aggregate proceeds of approximately $31,162,000. The Company incurred share issue costs of approximately $105,000 in respect of the offering.

COMMITMENTS

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to nine years. The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 2.3 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum payments for the firm service gas transportation agreements using current tariff rates and the non-cancellable building and office equipment leases as at December 31, 2015 are as follows:

($ 000s)	2016	2017	2018	2019	2020	Thereafter	Total
Firm service commitments	1,165	1,061	910	875	791	2,793	7,595
Office lease commitments	941	922	308	-	-	-	2,171
Total	2,106	1,983	1,218	875	791	2,793	9,766

DIVIDEND POLICY

For the year ended December 31, 2015, Bonterra paid dividends of $63,607,000 ($1.95 per share) compared to $113,007,000 ($3.54 per share) in 2014. 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 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 59 percent for the year ended December 31, 2015 (51 percent for the year ended December 31, 2014).

QUARTERLY FINANCIAL INFORMATION

	2015			
For the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Revenue – oil and gas sales	**44,678**	52,160	57,921	42,480
Cash flow from operations	**27,808**	36,024	17,960	26,079
Net earnings (loss)	**(4,113)**	(321)	(2,711)	(1,935)
Per share – basic	**(0.13)**	(0.01)	(0.08)	(0.06)
Per share – diluted	**(0.13)**	(0.01)	(0.08)	(0.06)

	2014			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	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	(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

The fluctuations in the Company's revenue and net earnings from quarter to quarter are primarily caused by variations in production volumes, realized commodity pricing and the related impact on royalties and production costs. In 2015, net earnings and cash flow are lower than prior periods due to a significant decrease in commodity prices, other than Q4 2014 net earnings which was lower due to the Company's tax agreement with the 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 (DC&P), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief Financial Officer of Bonterra evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Bonterra's DC&P were effective at December 31, 2015.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal control over financial reporting (ICFR), as defined in National Instrument 52-109, includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;

2. Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and

3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The CEO and CFO have designed, or caused to be designed under their supervision, ICFR as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013).

The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial period end of the Company and concluded that such internal controls over financial reporting are effective.

In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) published an updated Internal Control – Integrated Framework and related illustrative documents which supersedes the 1992 COSO Framework as of December 14, 2014. During the year, Bonterra has converted to the 2013 COSO framework.

It should be noted that while Bonterra's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and are effective; they do not expect that these controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that its objectives are met.

FINANCIAL REPORTING UPDATE

As of January 1, 2015, the Company early adopted IFRS 9 in accordance with the transitional provisions of that standard. A brief description of the new accounting policy and its impact on the Company's financial statements are as follows:

IFRS 9 "Financial Instruments"

Effective January 1, 2015 the Company adopted IFRS 9 "Financial Instruments". IFRS 9 replaces the sections of IAS 39 "Financial Instruments: Recognition and Measurements" that relates to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaces the multiple classification and measurement models for financial assets with a new model that only has two measurement categories; amortized cost and fair value through profit or loss or other comprehensive income. This determination is made at initial recognition. As a result of adopting IFRS 9, the Company's accounts receivables were reclassified from loans and receivables at amortized cost to financial assets at amortized cost. For financial liabilities, the new standard retains most of the IAS 39 requirements. The main change arises in cases where the Company chooses to designate a financial liability as fair value through net earnings. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income rather than net earnings. The Company has no financial liabilities that are measured at fair value through net earnings.

The classification of the Company's investments changed from available-for-sale to financial assets measured at fair value. On the day an investment is acquired the Company can make an irrevocable election (on an instrument by instrument basis) to designate investments in equity instruments as at fair value through other comprehensive income (FVTOCI), provided those investments are not classified as held for trading. The Company's investments will be measured at fair value, with gains or losses arising from changes in fair value recognized in other comprehensive income (loss) and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. The Company has designated all of its investments and its investment in a related party as FVTOCI on its initial adoption of IFRS 9.

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, 2018, 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.

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 17, 2016

ROBB D. THOMPSON
Chief Financial Officer

March 17, 2016

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, 2015 and 2014, and the statement of comprehensive income (loss), statement of cash flow 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, 2015 and 2014, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants, Chartered Accountants

March 17, 2016

Calgary, Canada

FINANCIAL STATEMENTS

STATEMENT OF FINANCIAL POSITION

As at ($ 000s)	Note	DECEMBER 31, 2015	December 31, 2014
ASSETS			
CURRENT			
Accounts receivable		**15,433**	20,314
Crude oil inventory		**868**	1,227
Prepaid expenses		**2,798**	2,428
Investments		**8,576**	6,228
		27,675	30,197
Investment in related party	7	**962**	1,738
Exploration and evaluation assets	8	**7,925**	7,629
Property, plant and equipment	5, 9	**1,045,387**	901,991
Investment tax credit receivable	16	**8,834**	8,573
Goodwill	10	**92,810**	92,810
		1,183,593	1,042,938
LIABILITIES			
CURRENT			
Accounts payable and accrued liabilities	11	**20,479**	31,839
Due to related party	12	**12,000**	12,000
Subordinated promissory note	13	**25,000**	40,000
		57,479	83,839
Bank debt	14	**332,471**	154,723
Decommissioning liabilities	15	**71,523**	53,792
Deferred tax liability	16	**126,315**	115,386
		587,788	407,740
COMMITMENTS AND SUBSEQUENT EVENTS	21, 22		
SHAREHOLDERS' EQUITY			
Share capital	17	**760,020**	728,934
Contributed surplus		**15,765**	11,495
Accumulated other comprehensive income		**571**	3,824
Retained earnings (deficit)		**(180,551)**	(109,055)
		595,805	635,198
		1,183,593	1,042,938

See accompanying notes to these financial statements.

On behalf of the board:

GEORGE F. FINK
Director

RODGER A. TOURIGNY
Director

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

FOR THE YEARS ENDED DECEMBER 31 ($ 000s, except $ per share)	Note	2015	2014
REVENUE			
Oil and gas sales, net of royalties	18	**183,878**	301,584
Other income	19	**328**	2,111
		184,206	303,695
EXPENSES			
Production		**55,215**	66,878
Office and administration		**3,302**	3,559
Employee compensation		**3,905**	7,111
Finance costs	6	**14,199**	7,104
Share-option compensation	17	**4,270**	2,725
Depletion and depreciation	9	**101,150**	106,697
Exploration and evaluation	8	**183**	28
		182,224	194,102
EARNINGS BEFORE INCOME TAXES		**1,982**	109,593
TAXES (RECOVERY)			
Current income tax (recovery)	16	**(355)**	10,505
Deferred income tax	16	**11,417**	60,327
		11,062	70,832
NET EARNINGS (LOSS) FOR THE YEAR		**(9,080)**	38,761
OTHER COMPREHENSIVE INCOME (LOSS)			
Unrealized gain (loss) on investments		**(2,519)**	1,174
Deferred taxes on unrealized (gain) loss on investments		**296**	(147)
Realized gain on investments transferred to net earnings		**-**	(1,102)
Deferred taxes on realized gain on investments transferred to net earnings		**-**	138
OTHER COMPREHENSIVE INCOME (LOSS) FOR THE YEAR		**(2,223)**	63
TOTAL COMPREHENSIVE INCOME (LOSS) FOR THE YEAR		**(11,303)**	38,824
NET EARNINGS (LOSS) PER SHARE – BASIC	17	**(0.28)**	1.21
NET EARNINGS (LOSS) PER SHARE – DILUTED	17	**(0.28)**	1.21
COMPREHENSIVE INCOME (LOSS) PER SHARE – BASIC	17	**(0.35)**	1.22
COMPREHENSIVE INCOME (LOSS) PER SHARE – DILUTED	17	**(0.35)**	1.21

See accompanying notes to these financial statements.

STATEMENT OF CASH FLOW

FOR THE YEARS ENDED DECEMBER 31 ($ 000s)	Note	2015	2014
OPERATING ACTIVITIES			
Net earnings (loss)		**(9,080)**	38,761
Items not affecting cash			
Deferred income taxes		**11,417**	60,327
Share-option compensation		**4,270**	2,725
Depletion and depreciation		**101,150**	106,697
Exploration and evaluation		**183**	28
Unwinding of the discount on decommissioning liabilities	15	**1,878**	1,361
Gain on sale of properties		**-**	(671)
Gain on sale of investments		**-**	(1,102)
Investment income		**(251)**	(56)
Interest expense		**12,321**	5,743
Change in non-cash working capital accounts:			
Accounts receivable		**4,419**	8,411
Crude oil inventory		**300**	(258)
Prepaid expenses		**(370)**	(786)
Investment tax credit receivable		**(261)**	6,646
Accounts payable and accrued liabilities		**(5,597)**	1,922
Decommissioning expenditures	15	**(187)**	(1,652)
Interest paid		**(12,321)**	(5,743)
CASH PROVIDED BY OPERATING ACTIVITIES		**107,871**	222,353
FINANCING ACTIVITIES			
Increase (decrease) in bank debt		**177,748**	(2,041)
Subordinated promissory note		**(15,000)**	15,000
Issuance of common shares by private placement		**31,162**	-
Share issue costs		**(105)**	-
Stock option proceeds		**-**	37,911
Dividends		**(63,607)**	(113,007)
CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES		**130,198**	(62,137)
INVESTING ACTIVITIES			
Investment income received		**251**	56
Exploration and evaluation expenditures	8	**(479)**	(402)
Property, plant and equipment expenditures	9	**(58,019)**	(155,262)
Proceeds on sale of properties		**-**	1,152
Purchase of investments		**(12,221)**	(1,527)
Proceeds on sale of investments		**8,130**	1,539
Acquisition	5	**(170,430)**	-
Change in non-cash working capital accounts:			
Accounts payable and accrued liabilities		**(5,763)**	(4,344)
Accounts receivable		**462**	(1,428)
CASH USED IN INVESTING ACTIVITIES		**(238,069)**	(160,216)
NET CHANGE IN CASH IN THE YEAR		**-**	-
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 17)	Share capital (Note 17)	Contributed surplus[1]	Accumulated other comprehensive income[2]	Retained earnings (deficit)	Total shareholders' equity
JANUARY 1, 2014	31,322,171	685,898	12,791	3,761	(34,809)	667,641
Share-option compensation			2,725			2,725
Share issuance	18,000	1,104				1,104
Exercise of options	829,452	37,911				37,911
Transfer to share capital on exercise of options		4,021	(4,021)			-
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
Share-option compensation			4,270			4,270
Share issuance, private placement	973,812	31,162				31,162
Share issue costs, net of tax		(76)				(76)
Comprehensive loss				(2,223)	(9,080)	(11,303)
Transfer of realized gain on investments				(1,191)	1,191	-
Deferred taxes on realized gain on investments				161		161
Dividends					(63,607)	(63,607)
DECEMBER 31, 2015	**33,143,435**	**760,020**	**15,765**	**571**	**(180,551)**	**595,805**

(1) Contributed surplus includes all amounts related to share-based payments.

(2) Accumulated other comprehensive income comprises of unrealized gains and losses on investments measured at fair value.

See accompanying notes to these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

As at and for the years ended December 31, 2015, and 2014.

1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. (Bonterra or the Company) is a public company listed on the Toronto Stock Exchange (the TSX) 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).

The financial statements were authorized for issue by the Company's Board of Directors on March 17, 2016.

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. See Note 4 for more information.

E) ADOPTED ACCOUNTING PRONOUNCEMENTS

As of January 1, 2015, the Company adopted the following new accounting pronouncement, in accordance with the transitional provision of the standard. A brief description of the new accounting policy and its impact on the Company's financial statements is as follows:

IFRS 9 "Financial Instruments"

Effective January 1, 2015 the Company adopted IFRS 9 "Financial Instruments". IFRS 9 replaces the sections of IAS 39 "Financial Instruments: Recognition and Measurements" that relates to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaces the multiple classification and measurement models for financial assets with a new model that only has two measurement categories; amortized cost and fair value through profit or loss or other comprehensive income (loss). This determination is made at initial recognition. As a result of adopting IFRS 9, the Company's accounts receivables were reclassified from loans and receivables at amortized cost to financial assets at amortized cost. For financial liabilities, the new standard retains most of the IAS 39 requirements. The main change arises in cases where the Company chooses to designate a financial liability as fair value through net earnings. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income (loss) rather than net earnings. The Company has no financial liabilities that are measured at fair value through net earnings.

The classification of the Company's investments changed from available-for-sale to financial assets measured at fair value. On the day an investment is acquired the Company can make an irrevocable election (on an instrument by instrument basis) to designate investments in equity instruments as at fair value through other comprehensive income (FVTOCI), provided those investments are not classified as held for trading. The Company's investments will be measured at FVTOCI, with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. The Company has designated all of its investments and its investment in a related party as FVTOCI on its initial adoption of IFRS 9.

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, 2018, 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.

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 party disclosure Notes 7 and 12).

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. The Company's investments are measured as fair value through other comprehensive income (FVTOCI), with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. 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.

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 proved plus probable developed reserve life. Proved plus probable developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of proved plus probable 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 and in 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 (loss). 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.

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. 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.

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 fair value through other comprehensive income (FVTOCI) 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). Goodwill is allocated to the CGU expected to benefit from the synergies of the combination. 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). The Company has a core CGU composed of its Alberta properties and secondary CGUs for its British Columbia (BC) and Saskatchewan properties.

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 (loss). 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 (loss). An impairment loss in respect of goodwill cannot be reversed.

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 liabilities, 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 (loss).

J) INCOME TAXES

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income (loss) 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 period end 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-OPTION COMPENSATION

The Company accounts for share-option compensation 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-option compensation is recognized through the statement of comprehensive income (loss) 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 (loss). 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

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost, financial liabilities at amortized costs; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instrument are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instrument are measured at amortized cost using the effective interest rate method.

Cash, account receivables and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are mainly payments of principle and interest. The Company's investments are measured at fair value through other comprehensive income (FVTOCI), with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. Accounts payable, accrued liabilities, and certain other long-term liabilities and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

M) FAIR VALUE MEASUREMENT

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related party, 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.

N) 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.

O) NET EARNINGS AND COMPREHENSIVE INCOME PER SHARE

Per share amounts are calculated by dividing the net earnings or comprehensive income (loss) 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. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

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 (PP&E) 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 PP&E. The determination of the Company's CGUs is subject to management's judgment. The Company has a core CGU composed of its Alberta properties and secondary CGUs for its BC and Saskatchewan properties.

The recoverable amount of E&E, PP&E, and goodwill is determined based on the fair value less costs of disposal using a discounted cash flow model and is assessed at the CGU level. The period the Company used to project cash flows is approximately 50 years or the CGU's reserve life. Growth in cash flow from a single well would be determined based on the extent of total reserves assigned, which is produced at declining rates over the estimated reserve life. The fair value measurement of the Company's E&E, PP&E, and goodwill is designated Level 3 on the fair value hierarchy.

For the year ended December 31, 2015, the Company performed an impairment test on all of its CGUs for any potential impairment or related recovery. In making these evaluations, the Company uses the following information:

1) The net present value of the pre-tax cash flows from oil and gas reserves of each CGU based on reserves estimated by the Company's independent reserve evaluator; and

2) Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

   a) Reserves – Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

   b) Crude oil and natural gas prices – Forward price estimates of the crude oil and natural gas prices are used in the cash flow model. Commodity prices used tend to be stable because short-term increases or decreases in prices are not considered indicative of long-term price levels, but nonetheless subject to change and the change could be material.

   c) Discount rate – The Company uses a pre-tax discount rate of 10 percent that reflects risks specific to the assets for which the future cash flow estimates have not been adjusted. The discount rate was determined based on the Company's assessment of risk based on past experience. Changes in the general economic environment could result in material changes to this estimate.

The following table from external sources outlines the forecast benchmark commodity prices used in the impairment calculation as at December 31, 2015:

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026(2)
WTI Crude oil $US per Bbl(1)	45.00	60.00	70.00	80.00	81.20	82.42	83.65	84.91	86.18	87.48	88.79
AECO C-Spot $ per Mmbtu(1)	2.25	2.95	3.42	3.91	4.20	4.28	4.35	4.43	4.51	4.59	4.67
Exchange rate $US per $Cdn	0.75	0.80	0.83	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

(1) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, transportation and marketing costs and other factors specific to the Company's operations in performing the Company's impairment tests.

(2) Forecast benchmark commodity prices are assumed to increase by 1.5% in each year after 2026 to the end of the reserve life.

With the current key assumptions listed above, the Company performed impairment tests for each CGU and concluded that no reasonable change in the key assumptions, such as a five percent change in commodity prices or a one percent change in the discount rate, would result in an impairment being recorded. For the years ended December 31, 2015 and 2014 no impairment losses were recorded in the statement of comprehensive income (loss).

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 CONTRACT

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-OPTION COMPENSATION

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.

5. ACQUISITION

On April 15, 2015, the Company acquired Cardium focused oil and gas assets in the Pembina area of Alberta, including upper zones (the Pembina Assets) that are complimentary to its existing Cardium oil and gas asset base. Cash consideration for these assets was $170,430,000. The results of the Pembina Assets have been included in these financial statements since that date. The Pembina Assets contributed oil and gas sales, net of royalties, of $20,667,000 and operating expenses of $10,448,000 for the period from April 15, 2015 to December 31, 2015. If the acquisition had occurred on January 1, 2015, total oil and gas sales, net of royalties, would have been approximately $28,127,000 and the total production costs would have been approximately $14,761,000 for the year ended December 31, 2015.

The acquisition has been accounted for using the acquisition method, and the purchase price was allocated to the assets acquired and the liabilities assumed as follows:

Net assets acquired:	($ 000s)
Property, plant and equipment	173,111
Decommissioning liabilities	(2,681)
Total	170,430

Consideration:	
Cash	170,430
Total purchase price	170,430

6. FINANCE COSTS

A breakdown of finance costs for the years ended:

($ 000s)	DECEMBER 31, 2015	December 31, 2014
Interest expense on bank debt	**10,390**	4,283
Interest expense on amounts owing to related party	**261**	285
Interest expense on subordinated promissory note and other	**1,670**	1,175
Unwinding of the fair value of decommissioning liabilities	**1,878**	1,361
	14,199	7,104

7. INVESTMENT IN RELATED PARTY

The investment consists of 1,034,523 (December 31, 2014 – 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 under the symbol PNE.

In addition, Pine Cliff owns 204,633 (December 31, 2014 – 204,633) common shares in Bonterra.

8. EXPLORATION AND EVALUATION ASSETS

($ 000s)	
COST AND CARRYING AMOUNT	
Balance at January 1, 2014	7,674
Additions	402
Dispositions	(419)
Expiry of exploration and evaluation assets	(28)
BALANCE AT DECEMBER 31, 2014	7,629
Additions	479
Expiry of exploration and evaluation assets	(183)
BALANCE AT DECEMBER 31, 2015	**7,925**

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.

9. PROPERTY, PLANT AND EQUIPMENT

COST ($ 000s)	OIL AND GAS PROPERTIES	PRODUCTION FACILITIES	FURNITURE, FIXTURES & OTHER EQUIPMENT	TOTAL PROPERTY, PLANT & EQUIPMENT
Balance at January 1, 2014	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
Disposals	(2)	(62)	-	(64)
BALANCE AT DECEMBER 31, 2014	1,028,520	252,521	1,987	1,283,028
Additions	42,093	15,860	66	58,019
Acquisition	138,711	34,400	-	173,111
Adjustment to decommissioning liabilities[1]	13,359	-	-	13,359
BALANCE AT DECEMBER 31, 2015	**1,222,683**	**302,781**	**2,053**	**1,527,517**

ACCUMULATED DEPLETION AND DEPRECIATION ($ 000s)	OIL AND GAS PROPERTIES	PRODUCTION FACILITIES	FURNITURE, FIXTURES & OTHER EQUIPMENT	TOTAL PROPERTY, PLANT & EQUIPMENT
Balance at January 1, 2014	(217,522)	(55,278)	(1,321)	(274,121)
Depletion and depreciation	(88,001)	(18,588)	(108)	(106,697)
Disposal and other	(219)	-	-	(219)
BALANCE AT DECEMBER 31, 2014	(305,742)	(73,866)	(1,429)	(381,037)
Depletion and depreciation	(84,800)	(16,250)	(100)	(101,150)
Disposal and other	57	-	-	57
BALANCE AT DECEMBER 31, 2015	**(390,485)**	**(90,116)**	**(1,529)**	**(482,130)**

CARRYING AMOUNTS AS AT: ($ 000s)				
December 31, 2014	722,778	178,655	558	901,991
DECEMBER 31, 2015	**832,198**	**212,665**	**524**	**1,045,387**

(1) Adjustment to decommissioning liabilities is due to a decrease in the risk free rate and changes in estimated decommissioning costs (see Note 15).

10. GOODWILL

The amount recorded as goodwill has all been allocated to the primary CGU, Alberta, Canada. There was no impairment loss recorded in the statement of comprehensive income (loss) for the years ended December 31, 2015 and 2014.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

($ 000s)	DECEMBER 31, 2015	December 31, 2014
Accounts payable	**15,130**	15,170
Accrued liabilities	**5,349**	16,669
	20,479	31,839

12. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2015, the Company's CEO, Chairman of the Board and major shareholder has a loan with the Company of $12,000,000 (December 31, 2014 – $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 2015 was $261,000 (December 31, 2014 – $285,000).

The Company received a management fee of $60,000 plus the reimbursement of certain administrative expenses for the year ended December 31, 2015 (December 31, 2014 – $60,000) for management services and office administration from Pine Cliff. This fee has been included in other income. As at December 31, 2015, the Company had an account receivable from Pine Cliff for these management fees and the reimbursement of certain administration expense of $293,000 (December 31, 2014 – $316,000).

COMPENSATION FOR KEY MANAGEMENT PERSONNEL

($ 000s)	DECEMBER 31, 2015	December 31, 2014
Compensation	**1,407**	2,272
Share-based payments	**1,595**	1,120
Total compensation	**3,002**	3,392

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

13. SUBORDINATED PROMISSORY NOTE

As at December 31, 2015, Bonterra had $25,000,000 (December 31, 2014 – $40,000,000) owed on a subordinated note to a private investor. 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 of $25,000,000 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 $974,000 (December 31, 2014 – $1,175,000). On January 22, 2016, the Company repaid $10,000,000.

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.

14. BANK DEBT

As at December 31, 2015, the Company has bank facilities consisting of a $375,000,000 (December 31, 2014 – $220,000,000) syndicated revolving credit facility and a $50,000,000 (December 31, 2014 – $30,000,000) non-syndicated revolving credit facility, for total credit facilities of $425,000,000. Amounts drawn under the credit facilities at December 31, 2015 were $332,471,000 (December 31, 2014 – $154,723,000). 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 provided by operating activities. The terms of the revolving credit facilities provided that the loan is revolving to April 29, 2016, with a maturity date of April 30, 2017 and is subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limits of the credit facilities are reviewed semi-annually on or before April 30 and October 31 each year based on the lender's interpretation of the Company's reserves, future commodity prices and costs.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $1,950,000 were issued as at December 31, 2015 (December 31, 2014 – $700,000). Security for credit facilities consists of various and floating demand debentures totaling $750,000,000 (December 31, 2014 – $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 covenants on the credit facilities:

- The Company cannot exceed $425,000,000 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 available cash flow for the preceding four fiscal quarters divided by four, which is calculated as 51 percent for the current quarter ended December 31, 2015.

Available cash flow is defined to be cash provided by operating activities excluding the change in non-cash working capital and decommissioning liabilities settled and including investment income received and all net proceeds of dispositions included in cash used in investing activities. At December 31, 2015, the Company is in compliance with all covenants.

15. DECOMMISSIONING LIABILITIES

At December 31, 2015, the estimated total undiscounted amount required to settle the decommissioning liabilities was $232,413,000 (December 31, 2014 – $177,441,000). The provision has been calculated assuming a 1.5 percent inflation rate (December 31, 2014 – 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, 2014 – 2.9 percent).

Changes to decommissioning liabilities were as follows:

($ 000s)	DECEMBER 31, 2015	December 31, 2014
Decommissioning liabilities, January 1	**53,792**	37,362
Acquisition (Note 5)	**2,681**	-
Adjustment to decommissioning liabilities[1]	**13,359**	16,721
Liabilities settled during the year	**(187)**	(1,652)
Unwinding of the discount on decommissioning liabilities	**1,878**	1,361
Decommissioning liabilities, end of year	**71,523**	53,792

(1) Adjustment to decommissioning liabilities is due to a change in the risk free rate and estimated decommissioning costs.

16. INCOME TAXES

($ 000s)	DECEMBER 31, 2015	December 31, 2014
Deferred tax asset (liability) related to:		
Investments	**(110)**	(566)
Exploration and evaluation assets and property, plant and equipment	**(148,961)**	(126,199)
Investment tax credits	**(2,385)**	(3,808)
Decommissioning liabilities	**19,311**	13,459
Corporate tax losses carried forward	**4,983**	-
Share issue costs	**737**	1,162
Corporate capital tax losses carried forward	**9,138**	8,617
Unrecorded benefit of capital tax losses carried forward	**(9,028)**	(8,051)
Deferred tax asset (liability)	**(126,315)**	(115,386)

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, 2015	December 31, 2014
Earnings before taxes	**1,982**	109,593
Combined federal and provincial income tax rates	**26.01%**	25.02%
Income tax provision calculated using statutory tax rates	**515**	27,420
Increase (decrease) in taxes resulting from:		
Change in statutory tax rates[1]	**8,490**	-
Stock-option compensation	**1,110**	682
Realized gain on sale of investments	**161**	-
Effect of Agreement	**-**	43,503
Change in estimates and other	**786**	(773)
Income tax expense	**11,062**	70,832

(1) Effective July 1, 2015 the combined federal and provincial income tax rate for Bonterra is approximately 27.00% due to the provincial tax rate for Alberta, Canada increasing from 10% to 12%.

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	112,723
Eligible capital expenditures	7	2,414
Share issue costs	20	2,729
Canadian oil and gas property expenditures	10	179,037
Canadian development expenditures	30	197,794
Canadian exploration expenditures	100	8,063
Income tax losses carried forward(1)	100	18,439
		521,199

(1) Income tax losses carried forward expire in 2035.

The Company has $8,834,000 (December 31, 2014 – $8,573,000) of investment tax credits that expire in the following years; 2021 – $1,824,000; 2022 – $1,735,000; 2023 – $1,097,000; 2024 – $1,241,000; 2025 – $1,323,000; 2026 – $1,105,000; 2027 – $410,000; and 2035 – $99,000.

The Company has $67,691,000 (December 31, 2014 - $68,881,000) 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 (loss). Of the $10,505,000 current tax provision for 2014 fiscal year, $6,645,000 of the federal investment tax credit receivable was used to reduce current taxes payable to $3,860,000. No current taxes are owing for the 2015 fiscal year.

17. SHAREHOLDERS' EQUITY

AUTHORIZED

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

	DECEMBER 31, 2015		December 31, 2014	
Issued and fully paid – common shares	**NUMBER**	**AMOUNT ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**32,169,623**	**728,934**	31,322,171	685,898
Share issuance, private placement	**973,812**	**31,162**	-	-
Share issue costs, net of tax		**(76)**		-
Issued pursuant to the Company's share option plan	**-**	**-**	829,452	37,911
Transfer from contributed surplus to share capital		**-**		4,021
Shares issued for oil and gas properties	**-**	**-**	18,000	1,104
Balance, end of year	**33,143,435**	**760,020**	32,169,623	728,934

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.

On July 8, 2015, the Company closed a private placement of 973,812 common shares to existing shareholders at a price of $32.00 per share, for aggregate proceeds of approximately $31,162,000. The Company incurred issue costs of approximately $105,000 in respect of the offering.

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

	DECEMBER 31, 2015	December 31, 2014
Basic shares outstanding	**32,641,855**	31,921,623
Dilutive effect of share options(1)	**-**	114,022
Diluted shares outstanding	**32,641,855**	32,035,645

(1) The Company did not include 2,955,500 share options (December 31, 2014 – 1,100,000) in the dilutive effect of share options calculation as these share options were anti-dilutive.

For the year ended December 31, 2015, the Company declared and paid dividends of $63,607,000 ($1.95 per share) (December 31, 2014 – $113,007,000 ($3.54 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 3,314,344 (December 31, 2014 – 3,216,962) 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, 2015, and changes during the period ended on those dates is presented below:

	NUMBER OF OPTIONS		**WEIGHTED AVERAGE EXERCISE PRICE**
At January 1, 2014	1,650,500	$	48.31
Options granted	1,769,000		56.48
Options exercised	(904,000)(1)		47.09
Options cancelled	(194,000)		49.09
Options forfeited	(210,000)		55.01
At December 31, 2014	2,111,500	$	54.94
Options granted	1,772,500		28.15
Options expired	(928,500)		50.46
AT DECEMBER 31, 2015	**2,955,500**	**$**	**40.28**

(1) 93,000 options were exercised under the cashless option method, which resulted in 18,452 shares being issued in which the Company received no proceeds.

The following table summarizes information about options outstanding at December 31, 2015:

	Options Outstanding				Options Exercisable		
Range of exercise prices	Number outstanding at December 31, 2015	Weighted-average remaining contractual life		Weighted-average exercise price	Number exercisable at December 31, 2015		Weighted-average exercise price
$ 20.00 – $ 30.00	807,000	1.7 years	$	20.46	-	$	-
30.01 – 40.00	965,500	1.8 years		34.57	-		-
40.01 – 65.00	1,183,000	0.8 years		58.46	164,000		51.52
$ 20.00 – $ 65.00	2,955,500	1.4 years	$	40.28	164,000	$	51.52

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 2015, the Company granted 1,772,500 stock options with an estimated fair value of $6,523,000 or $3.68 per option using the Black-Scholes option pricing model with the following key assumptions:

	DECEMBER 31, 2015	December 31, 2014
Weighted-average risk free interest rate (%)(1)	**0.48**	1.04
Expected life (years)	**1.5**	1.5
Weighted-average volatility (%)(2)	**39.93**	17.63
Forfeiture rate (%)	**9.24**	5.00
Weighted average dividend yield (%)	**6.84**	5.66

(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.

18. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	**DECEMBER 31, 2015**	December 31, 2014
Oil and gas sales	**197,239**	339,694
Less:		
Crown royalties	**(8,007)**	(23,779)
Freehold, gross overriding royalties and other	**(5,354)**	(14,331)
Oil and gas sales, net of royalties	**183,878**	301,584

19. OTHER INCOME

($ 000s)	**DECEMBER 31, 2015**	December 31, 2014
Investment income	**251**	56
Administrative income	**77**	282
Gain on sale of properties	**-**	671
Realized gain on investments	**-**	1,102
Other income	**328**	2,111

20. 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 from operating activities. 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 did not meet its annual guidance with a net debt to cash flow level of 3.4:1. The increase in net debt to cash flow ratio is primarily due to the acquisition of the Pembina Assets (see acquisition Note 5) and low commodity prices realized in 2015. To manage its bank debt during a period of low commodity prices the Company significantly reduced planned capital expenditures for the 2015 fiscal year and in February 2015 reduced the monthly dividend by $0.15 per common share. In January of 2016 the Company reduced the monthly dividend by a further $0.05 to $0.10 per common share. In addition the Company raised approximately $31 million in equity by way of a private placement (see shareholders' equity Note 17).

Section (a) of this note provides the Company's debt to cash flow from operations.

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.

a) Net Debt Ratio

The net debt and cash flow amounts as of December 31, 2015 are as follows:

($ 000s)	
Bank debt	**332,471**
Accounts payable and accrued liabilities	**20,479**
Due to related party	**12,000**
Subordinated promissory note	**25,000**
Current assets	**(27,675)**
Net debt	**362,275**
Cash flow from operations	**107,871**
Net debt to annual cash flow from operations	**3.4**

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 $375,000,000 syndicated revolving operating line, $50,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $25,000,000 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 $2,515,000.

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 $15,433,000 accounts receivable balance at December 31, 2015 (December 31, 2014 – $20,314,000) over 83 percent (2014 – 80 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, 2015, 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, 2015, approximately $1,077,000 or seven percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2014 – $2,948,000 or 14.5 percent). The majority of these accounts are due from various joint venture 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 venture 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, 2015 is $365,000 (December 31, 2014 – $308,000) 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 9 years
Accounts payable and accrued liabilities	Yes – Liability	20,479	-
Due to related party	Yes – Liability	12,000	-
Subordinated promissory note	Yes – Liability	25,000	-
Bank debt	Yes – Liability	-	332,471
Firm service commitments	No	1,165	6,430
Office lease commitments	No	941	1,230
Total		59,585	340,131

21. COMMITMENTS

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to nine years. The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 2.3 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum payments for the firm service gas transportation agreements using current tariff rates and the non-cancellable building and office equipment leases as at December 31, 2015 are as follows:

($ 000s)	2016	2017	2018	2019	2020	Thereafter	Total
Firm service commitments	1,165	1,061	910	875	791	2,793	7,595
Office lease commitments	941	922	308	-	-	-	2,171
Total	2,106	1,983	1,218	875	791	2,793	9,766

22. SUBSEQUENT EVENTS

i) DIVIDENDS

Subsequent to December 31, 2015, the Company declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 4, 2016	January 15, 2016	0.10	January 29, 2016
February 1, 2016	February 16, 2016	0.10	February 29, 2016
March 1, 2016	March 15, 2016	0.10	March 31, 2016

CORPORATE INFORMATION

BOARD OF DIRECTORS

G. F. Fink – Chairman
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
TD Securities, Calgary, Alberta
J.P. Morgan, Calgary, Alberta
Alberta Treasury Branch, Calgary, Alberta

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