MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated March 13, 2018 is a review of the operations and current financial position for the year ended December 31, 2017 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 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. The Company calculates net debt as long-term debt plus working capital deficiency (current liabilities less current assets).

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; "AECO" refers to Alberta Energy Company, a grade or heating content of natural gas used as benchmark pricing in Alberta, Canada; "bbl" refers to barrel; "NGL" refers to Natural gas liquids; "MCF" refers to thousand cubic feet; "MMBTU" refers to million British Thermal Units; "GJ" refers to gigajoule; 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 COMPARISIONS

As at and for the year ended ($000s except $ per share)		**December 31, 2017**	December 31, 2016	December 31, 2015 [1]
FINANCIAL				
Revenue - realized oil and gas sales		**202,566**	169,863	197,239
Cash flow from operations		**103,873**	75,294	107,871
Per share - basic and diluted		**3.12**	2.26	3.30
Payout ratio		**38%**	53%	59%
Cash dividends per share		**1.20**	1.20	1.95
Net earnings (loss)		**2,506**	(24,135)	(9,080)
Per share - basic and diluted		**0.08**	(0.73)	(0.28)
Capital expenditures, net of disposition		**82,441** [3]	40,797	58,498
Acquisition		**-**	-	170,430 [2]
Disposition		**56,752** [3]	-	-
Total assets		**1,125,551**	1,147,834	1,183,593
Working capital deficiency		**27,790**	24,921	29,804
Long-term debt		**292,212**	329,204	332,471
Shareholders' equity		**510,260**	543,824	595,805
OPERATIONS				
Oil	-bbl per day	**7,907**	7,942	8,641
	-average price ($ per bbl)	**59.30**	49.46	54.08
NGLs	-bbl per day	**905**	894	733
	-average price ($ per bbl)	**31.47**	19.93	20.80
Natural gas	-MCF per day	**24,087**	22,888	19,694
	-average price ($ per MCF)	**2.40**	2.34	2.94
Total barrels of oil equivalent per day (BOE)		**12,827**	12,650	12,656

(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) For 2017, includes the Disposition of a two percent gross overriding royalty (“GORR”) interest on the total production from the Company’s Pembina Cardium pool that closed December 20, 2017 and is effective January 1, 2018. Consideration consisted of $52 million of cash and incremental Cardium assets valued at $4.7 million which is included in capital expenditures (refer to Note 5 of the December 31, 2017 audited annual financial statements).

QUARTERLY COMPARISONS

	2017			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	**54,192**	46,349	52,695	49,330
Cash flow from operations	**26,472**	25,491	27,370	24,540
Per share - basic and diluted	**0.79**	0.77	0.82	0.74
Payout ratio	**38%**	40%	37%	41%
Cash dividends per share	**0.30**	0.30	0.30	0.30
Net earnings (loss)	**2,096**	(3,043)	2,978	475
Per share - basic and diluted	**0.06**	(0.09)	0.09	0.01
Capital expenditures	**18,775** (1)	14,121	19,416	30,129
Disposition	**56,752** (1)	-	-	-
Total assets	**1,125,551**	1,146,498	1,173,936	1,156,398
Working capital deficiency	**27,790**	28,260	29,759	39,483
Long-term debt	**292,212**	345,322	341,070	330,118
Shareholders' equity	**510,260**	517,719	529,844	535,742
Operations				
Oil (barrels per day)	**7,766**	8,038	8,287	7,533
NGLs (barrels per day)	**963**	1,000	843	813
Natural gas (MCF per day)	**24,466**	25,460	24,138	22,243
Total BOE per day	**12,807**	13,281	13,153	12,053

(1) For Q4 2017, includes the Disposition of a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool that closed December 20, 2017 and is effective January 1, 2018. Consideration consisted of $52 million of cash and incremental Cardium assets valued at $4.7 million which is included in capital expenditures (refer to Note 5 of the December 31, 2017 audited annual financial statements).

	2016			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	48,967	46,236	41,150	33,510
Cash flow from operations	31,537	19,219	13,392	11,146
Per share - basic and diluted	0.94	0.58	0.40	0.34
Payout ratio	32%	52%	75%	89%
Cash dividends per share	0.30	0.30	0.30	0.30
Net loss	(1,168)	(5,830)	(5,582)	(11,555)
Per share - basic and diluted	(0.03)	(0.18)	(0.17)	(0.35)
Capital expenditures, net of dispositions	12,270	17,424	9,420	1,683
Total assets	1,147,834	1,163,743	1,169,782	1,174,141
Working capital deficiency	24,921	26,361	18,429	13,115
Long-term debt	329,204	335,953	336,923	345,118
Shareholders' equity	543,824	549,870	564,075	575,925
Operations				
Oil (barrels per day)	7,467	8,197	7,780	8,325
NGLs (barrels per day)	911	942	877	845
Natural gas (MCF per day)	22,540	24,948	21,771	22,274
Total BOE per day	12,134	13,298	12,285	12,882

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, differentials 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 also outlined in detail in the following table.

	Q4-2017	Q3-2017	Q2-2017	Q1-2017	Q4-2016	Q3-2016	Q2-2016	Q1-2016
Crude oil								
WTI (U.S.$/bbl)	**55.40**	48.30	48.28	51.91	49.29	44.94	45.59	33.45
WTI to MSW Stream Index								
Differential (U.S.$/bbl)(1)	**(1.14)**	(2.89)	(2.26)	(3.60)	(3.09)	(3.02)	(3.14)	(3.78)
Foreign exchange								
U.S.$ to Cdn$	**1.2717**	1.2524	1.3447	1.3230	1.3339	1.3051	1.2886	1.3748
Bonterra average realized								
oil price (Cdn$/bbl)	**65.16**	53.48	58.27	60.63	58.02	51.80	51.64	37.33
Natural gas								
AECO (Cdn$/mcf)	**1.68**	1.45	2.77	2.68	3.08	2.31	1.39	1.82
Bonterra average realized								
gas price (Cdn$/mcf)	**1.90**	1.81	3.03	2.97	3.32	2.47	1.48	2.02

(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 or factors, including but not limited to:

- Worldwide crude oil supply and demand imbalance;
- Geo-political events that affect worldwide crude oil supply and demand;
- The value of the Canadian dollar compared to the US dollar;
- Access to infrastructure and markets;
- Weather; and
- Timing and duration of plant, refinery and pipeline maintenance.

Global and local supply and demand imbalances have placed continued pressure on oil, natural gas and liquids pricing since 2015 resulting in commodity price volatility. WTI benchmark pricing which has been steadily increasing from the low of $30.62 US per bbl in February of 2016, continued to increase in the fourth quarter of 2017 to over $55.00 US per barrel. This price increase has been attributed to reductions in global crude oil inventories and increased global demand from emerging markets. With the 2016 OPEC agreement extended through 2018, this trend is anticipated to continue, although it may be tempered somewhat if US shale production continues to increase. In November of 2017 the Keystone pipeline had a crude oil spill in South Dakota, USA. The Keystone pipeline is currently not running at capacity which has led to reduced transportation of oil and storage issues for crude oil in the western Canadian sedimentary basin. This spill has had an impact on the WTI to Edmonton Par or MSW stream index (both light sweet crude benchmarks), which has widened in the first quarter of 2018. Several export pipeline projects were approved including TransMountain Pipeline, Enbridge Line 3 Expansion and Keystone XL. Completion of any of these projects may have a positive effect on the movement and pricing of Canadian barrels.

The AECO benchmark price for natural gas improved somewhat through the fourth quarter of 2017 compared to the third quarter of 2017. This was mainly due to the onset of winter and increased heating demand. Western Canadian supply continues to hover near historically high levels. Should this continue into 2018, pipeline infrastructure will struggle to handle all of the existing and incremental volumes which is anticipated to put downward pressure on natural gas prices.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant.

Annualized sensitivity analysis on cash flow, as estimated for 2018 [(1)]

Impact on cash flow	Change ($)	$000s	$ per share [(2)]
Realized crude oil price ($/bbl)	1.00	2,772	0.08
Realized natural gas price ($/mcf)	0.10	915	0.03
U.S.$ to Canadian $ exchange rate	0.01	369	0.01

(1) This analysis uses current royalty rates, annualized estimated average production of 13,200 BOE per day and no changes in working capital

(2) Based on annualized basic weighted average shares outstanding of 33,310,796

Business Overview, Strategy and Key Performance Drivers

Bonterra is an upstream 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 Pembina Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original oil in place with very low recoveries to date. Bonterra operates 88.5 percent of its production with an average working interest of 76 percent and operates the majority of its related oil and gas processing facilities, which require minimal additional capital to increase production. At December 31, 2017, Bonterra has identified horizontal drilling inventory of 735 net Cardium locations. Bonterra has also identified additional drilling locations in other formations within Alberta, Saskatchewan and British Columbia.

On December 20, 2017, the Company sold a two percent gross overriding royalty (GORR) on all of the production from the Company's Pembina Cardium pool effective January 1, 2018. The royalty owner has the option of either being paid in cash or in kind. Consideration received on disposition was $52,000,000 in cash and incremental Cardium assets valued at $4,747,000. This transaction enabled Bonterra to crystalize value from its attractive, long-life and predictable asset base, lowered debt and improve its debt to cash flow ratio without dilution to the shareholders. The increase in royalty payments compared to the finance cost savings is not expected to have a material impact to the Company's cash flow.

The Company averaged 12,827 BOE per day for 2017 which was in line with its revised annual production guidance of 12,900 BOE per day. Bonterra continues to manage production volumes on a month to month basis and uses commodity prices, availability of drilling and completion service providers and seasonal weather conditions to determine its capital expenditures so as to maximize cash flow and manage debt levels over an annual period. During the first quarter of 2017, the Company experienced challenges accessing fracking services, thereby preventing new wells from being placed on production until the second quarter. Also in the second and third quarter of 2017 the Company realized lower commodity prices due to a decrease in WTI and a strengthening of the Canadian dollar, which caused the Company to defer drilling five (4.4 net) wells. With an increase in WTI and weakening of the Canadian dollar in the fourth quarter of 2017, the Company accelerated its drilling program and was able to drill, complete and tie-in those wells within the quarter. In addition, in the fourth quarter of 2017, 298 BOE per day was shut-in or stored in inventory due to freeze-offs and pipeline restrictions. The combination of these events, negatively affected annual production and were the primary reasons the Company did not average over 13,000 BOE per day for 2017. The Company expects to minimize capital spending challenges in 2018 and is forecasting 2018 annual production guidance to be between 13,200 to 13,500 BOE per day.

In 2017, Bonterra invested approximately $60,700,000 to drill 30 gross operated (27.9 net) horizontal wells and complete and tie-in 33 gross (29.6 net) wells (of which three (1.7 net) wells were drilled in 2016, but not completed until 2017). In addition, approximately $17,000,000 was directed towards adding and improving infrastructure and non-operated capital programs. In December of 2017, the Company set its capital expenditure budget for 2018 at approximately $75,000,000.

On November 1, 2017, following the semi-annual review of its bank facility, the Company's borrowing base was successfully renewed at $380,000,000. The bank facility is comprised of a $330,000,000 syndicated revolving credit facility, and a $50,000,000 non-syndicated revolving credit facility. The revolving period on the bank facility expires on April 30, 2018, with a maturity date of April 30, 2019, subject to an annual review. As at December 31, 2017, Bonterra had $292,000,000 drawn on the $380,000,000 bank facility. These credit facilities provide the Company with sufficient liquidity and financial flexibility to execute its business plan.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending and monthly dividends, ability to maintain desired levels of production, control over infrastructure, efficiency in developing and operating properties, and the 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, 2017		September 30, 2017		December 31, 2016		**December 31, 2017**		December 31, 2016	
	Gross[(1)]	**Net[(2)]**	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	**Gross[(1)]**	**Net[(2)]**	Gross[(1)]	Net[(2)]
Crude oil horizontal-operated	**5**	**4.4**	4	4.0	4	2.7	**30**	**27.9**	21	18.7
Crude oil horizontal-non-operated	**2**	**0.2**	-	-	2	0.1	**8**	**1.7**	2	0.1
Total	**7**	**4.6**	4	4.0	6	2.8	**38**	**29.6**	23	18.8
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 the first quarter of 2017, the Company placed three gross (1.7 net) wells on production that were drilled in the later part of 2016. In addition, the Company drilled, completed and tied-in 30 gross (27.9 net) wells during 2017.

In addition, eight gross (1.7 net) non-operated wells were drilled and completed during 2017, of which six (1.0 net) were put on production. The remaining two wells are expected to be on production in the first quarter of 2018.

Production

	Three months ended			Year ended	
	December 31, 2017	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Crude oil (barrels per day)	**7,766**	8,038	7,467	**7,907**	7,942
NGLs (barrels per day)	**963**	1,000	911	**905**	894
Natural gas (MCF per day)	**24,466**	25,460	22,540	**24,087**	22,888
Average BOE per day	**12,807**	13,281	12,134	**12,827**	12,650

Annual production volumes for 2017 were in line with 2016. Due to the challenges of procuring fracking services in the first quarter of 2017, which caused delays with bringing eleven (9.6 net) new wells on production; new production was deferred from the first quarter of 2017 to the second quarter of 2017. Due to declining realized commodity prices in Q3 2017, the Company also deferred drilling, completing and tying-in five (4.5 net) wells until Q4 2017. The deferred drilling program resumed due to realized prices increasing by 22 percent from Q3 2017 to Q4 2017. These delays in bringing on new production resulted in a substantial reduction in annual production volumes for 2017. During the fourth quarter, production decreased 474 BOE per day compared to the third quarter of 2017, partially due to 218 BOE per day being shut-in due to freeze offs from extremely cold weather and 80 barrels per day of crude oil in field storage due to pipeline restrictions. All restricted pipeline volumes that were stored in field inventory will be included in Q1 2018 production.

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	
	December 31,	September 30,	December 31,	**December 31,**	December 31,
$ per BOE	**2017**	2017	2016	**2017**	2016
Production volumes (BOE)	**1,178,212**	1,221,852	1,116,357	**4,681,773**	4,629,972
Gross production revenue	**46.09**	37.93	43.86	**43.29**	36.69
Royalties	**(3.37)**	(2.59)	(2.76)	**(3.03)**	(2.11)
Production costs	**(14.79)**	(12.54)	(12.12)	**(13.26)**	(11.77)
Field netback	**27.93**	22.80	28.98	**27.00**	22.81
General and administrative	**(1.37)**	(1.72)	(1.18)	**(1.66)**	(1.37)
Interest and other	**(3.58)**	(3.49)	(3.92)	**(3.49)**	(3.73)
Cash netback	**22.98**	17.59	23.88	**21.85**	17.71

Cash netbacks have increased in 2017 compared to 2016 primarily due to increased commodity prices. This increase was partially offset by increased royalties, production costs and general and administrative costs. The increase in quarter over quarter cash netbacks was primarily the result of an increase in commodity prices, which was partially offset by an increase in production costs from deferred well and lease maintenance programs. With previously deferred well and lease maintenance programs being completed and field optimization infrastructure added during 2017, production costs per BOE on an annual basis are expected to decrease in 2018 compared to 2017.

Oil and Gas Sales

	Three months ended			Year ended	
	December 31,	September 30,	December 31,	**December 31,**	December 31,
	2017	2017	2016	**2017**	2016
Revenue - oil and gas sales ($ 000s)	**54,192**	46,349	48,967	**202,566**	169,863
Average realized prices:					
Crude oil ($ per barrel)	**65.16**	53.48	58.02	**59.30**	49.46
NGLs ($ per barrel)	**39.12**	27.81	26.64	**31.47**	19.93
Natural gas ($ per MCF)	**1.90**	1.81	3.32	**2.40**	2.34
Average ($ per BOE)	**46.09**	37.93	43.86	**43.29**	36.69
Average BOE per day	**12,807**	13,281	12,134	**12,827**	12,650

Revenue from oil and gas sales increased by $32,703,000 in 2017, or 19 percent, compared to the same period a year ago. This increase was primarily driven by higher oil prices. The quarter over quarter increase in oil and gas sales was primarily due to increased commodity prices, which was partially offset by a decrease in production volumes.

The Company's product split on a revenue basis for 2017 is approximately 90 percent weighted towards crude oil and NGLs.

Royalties

($ 000s)	Three months ended **December 31, 2017**	September 30, 2017	December 31, 2016	Year ended **December 31, 2017**	December 31, 2016
Crown royalties	**2,913**	2,299	1,951	**10,178**	5,917
Freehold, gross overriding and other royalties	**1,061**	865	1,126	**4,026**	3,864
Total royalties	**3,974**	3,164	3,077	**14,204**	9,781
Crown royalties - percentage of revenue	**5.4**	5.0	4.0	**5.0**	3.5
Freehold, gross overriding and other royalties - percentage of revenue	**2.0**	1.9	2.3	**2.0**	2.3
Royalties - percentage of revenue	**7.4**	6.9	6.3	**7.0**	5.8
Royalties $ per BOE	**3.37**	2.59	2.76	**3.03**	2.11

Royalties paid by the Company consist of crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and non-crown royalties. Total royalties on a per BOE basis increased by $0.92 per BOE for 2017 compared to 2016 and increased by $0.78 per BOE for Q4 2017 compared to Q3 2017 primarily due to an increase in commodity prices.

Production Costs

($ 000s except $ per BOE)	Three months ended **December 31, 2017**	September 30, 2017	December 31, 2016	Year ended **December 31, 2017**	December 31, 2016
Production costs	**17,428**	15,319	13,536	**62,066**	54,503
$ per BOE	**14.79**	12.54	12.12	**13.26**	11.77

Production costs for 2017 increased by $1.49 per BOE compared to 2016, primarily due to an increase in service rigs, equipment and lease maintenance costs. In the first quarter of 2016, Bonterra elected to shut-in higher production cost areas due to extremely depressed crude oil prices experienced during that period. The Company did reactivate a portion of this production in the third and fourth quarter of 2016. However, a portion of the well service and lease maintenance costs were deferred into 2017. With rising commodity prices in the fourth quarter of 2017, the Company also elected to expedite its well maintenance program to limit well downtime and reactive further down wells to increase production and cash flow. In addition, power and chemical costs in 2017 increased approximately $800,000 compared to 2016. To reduce production costs going forward, the Company incurred infrastructure capital to reduce gathering, compression, water hauling and injection costs in 2017. With the completion of the deferred well service and lease maintenance activities, and the enhanced infrastructure in place for 2018 the Company anticipates 2018 annual production costs to be lower than $13.26 per BOE incurred in 2017.

Quarter over quarter, production costs increased on a per BOE basis primarily due to accelerated well maintenance programs as the Company doubled the service rigs from two to four in order to reactivate down wells that were deferred until the fourth quarter of 2017 as realized commodity prices increased. Also, cold weather contributed to shut-in production and increased chemical and maintenance costs that negatively affected production costs on a per BOE basis.

Other Income

($ 000s)	Three months ended December 31, **2017**	September 30, 2017	December 31, 2016	Year ended December 31, **2017**	December 31, 2016
Investment income	**33**	18	10	**74**	18
Administrative income	**108**	85	70	**297**	214
Gain on sale of property	**4,233**	-	1	**4,233**	1
	4,374	103	81	**4,604**	233

In the fourth quarter of 2017, Bonterra sold a two percent overriding royalty interest on all the total production from the Company's Pembina Cardium pool, with an effective date of January 1, 2018. Consideration received on disposition was $56,747,000, comprised of $52,000,000 in cash and property, plant and equipment valued at $4,747,000. The result of this disposition was a gain on disposal of $4,226,000 and deferred consideration of $16,064,000. Deferred consideration was determined for an upfront payment received for the implicit obligation of future extraction services that will generate future royalties. Beginning on January 1, 2018, deferred consideration will be recognized into income at the same depletion rate as the Pembina Cardium pool assets.

The market value of the investments held by the Company at December 31, 2017 was $750,000 (December 31, 2016 - $1,621,000). The carrying value decreased due to a decrease in the investments carrying value. Dispositions resulted in a gain on sale of $nil (December 31, 2016 - $3,047,000) which was recorded as an equity transfer between accumulated other comprehensive income and retained earnings.

The Company receives administrative income for various oil and gas administrative services and production equipment rentals.

General and Administration (G&A) Expense

($ 000s except $ per BOE)	Three months ended December 31, **2017**	September 30, 2017	December 31, 2016	Year ended December 31, **2017**	December 31, 2016
Employee compensation expense	**1,007**	959	894	**4,535**	3,755
Office and administrative expense	**611**	1,137	421	**3,214**	2,584
Total G&A expense	**1,618**	2,096	1,315	**7,749**	6,339
$ per BOE	**1.37**	1.72	1.18	**1.66**	1.37

The increase of $780,000 in employee compensation expense for 2017 compared to 2016 is primarily due to a one-time bonus paid to staff and consultants in lieu of compensation increases over the past two years and to stay competitive with similar sized companies in the resource industry. 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 corporate performance clearly aligns the interests of the employees with those of shareholders.

Office and administration expense for 2017 increased compared to 2016 primarily due to an increase in the allowance for doubtful accounts and insurance premiums, which was partially offset by a decrease in continuous disclosure fees, lower banking renewal fees and more overhead recoveries resulting from fewer wells being shut-in and more wells being drilled compared to 2016. The quarter over quarter decrease in office and administrative expense is primarily due to a decrease in the allowance for doubtful accounts.

Finance Costs

($ 000s except $ per BOE)	Three months ended December 31, 2017	Three months ended September 30, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Interest on long-term debt	**4,129**	4,142	4,240	**15,807**	16,708
Other interest	**235**	231	219	**899**	789
Interest expense	**4,364**	4,373	4,459	**16,706**	17,497
$ per BOE	**3.70**	3.58	3.99	**3.57**	3.78
Unwinding of the discounted value of decommissioning liabilities	**761**	763	659	**3,013**	2,507
Total finance costs	**5,125**	5,136	5,118	**19,719**	20,004

Interest on long-term debt decreased slightly for 2017 compared to 2016 as the Company realized lower interest rates due to a lower net debt to EBITDA ratio. Interest rates are determined quarterly for the subsequent quarter by the ratio of total debt (excluding accounts payable and accrued liabilities) to current quarter EBITDA (defined as net income excluding finance costs, provision for current and deferred taxes, depletion and depreciation, share-option compensation, gain or loss on sale of assets and impairment of assets) multiplied by four.

Other interest relates to amounts paid to a related party (see related party transactions) and a $12,500,000 subordinated promissory note from a private investor. On February 9, 2018, the Company repaid $2,500,000 of the subordinated promissory note. For more information about the subordinated promissory note, refer to Note 13 of the December 31, 2017 audited annual financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,221,000.

Share-Option Compensation

($ 000s)	Three months ended December 31, 2017	Three months ended September 30, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Share-option compensation	**604**	1,029	1,756	**4,511**	5,818

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 decreased by $1,307,000 from a year ago due to the majority of the options issued being granted in the fourth quarter in 2017 compared to the third quarter of 2016 and lower share price volatility in the current year. Quarter over quarter share-option compensation decreased due to the majority of 2016 share-options being fully amortized at the end of the third quarter of 2017.

Based on the outstanding options as of December 31, 2017, the Company has an unamortized expense of $3,402,000, of which $2,477,000 will be recorded for 2018, $907,000 for 2019 and $18,000 thereafter. For more information about options issued and outstanding, refer to Note 18 of the December 31, 2017 audited annual financial statements.

Depletion and Depreciation, Exploration and Evaluation (E&E) and Goodwill

($ 000s)	Three months ended December 31, 2017	Three months ended September 30, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Depletion and depreciation	**22,912**	22,349	22,818	**89,339**	100,992
Exploration and evaluation	**1,566**	-	-	**1,566**	-
Impairment of oil and gas assets	**-**	-	2,505	**-**	2,505

The provision for depletion and depreciation decreased by $11,653,000 for 2017 compared to 2016. The decrease in depletion and depreciation is primarily due to lower depletion rates resulting from an increase in previously estimated reserves over 2016.

Exploration and evaluation expense related to expired leases.

On December 31, 2016, the Company recorded a $799,000 impairment charge to E&E expenditures and $1,706,000 to Property, Plant and Equipment (PPE) for a total impairment charge of $2,505,000 all related to its non-core British Columbia gas properties. There were no impairment provisions recorded for the year ended December 31, 2017.

Taxes

The Company recorded a total tax expense of $5,510,000 (2016 – total tax recovery of $5,711,000). The increase in the total tax expense is due to an increase in net earnings before income taxes, a valuation allowance of $1,901,000 on its non-core successored resource related pools and a provincial tax loss carryback accrued in the prior year for taxes paid in prior periods.

For additional information regarding income taxes, see Note 17 of the December 31, 2017 audited annual financial statements.

Net Earnings (Loss)

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2017**	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Net earnings (loss)	**2,096**	(3,043)	(1,168)	**2,506**	(24,135)
$ per share - basic	**0.06**	(0.09)	(0.03)	**0.08**	(0.73)
$ per share - diluted	**0.06**	(0.09)	(0.03)	**0.08**	(0.73)

Net earnings for 2017 increased by $26,641,000 compared to 2016. The increase in net earnings was mainly due to increased commodity prices, a gain on disposal and a decrease in depletion and depreciation. The increase in net earnings was partially offset by an increase in royalties, production costs, exploration and evaluation expense and an income tax recovery in 2016.

The quarter over quarter increase in net earnings was mainly due to an increase in commodity prices and a gain on disposal, partially offset by an increase in production costs, exploration and evaluation expense and deferred tax expense.

Other Comprehensive Income (Loss)

Other comprehensive income for 2017 consists of an unrealized loss before tax on investments (including investment in a related party) of $871,000 relating to a decrease in the investments' fair value (December 31, 2016 – unrealized gain of $2,866,000). 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 a related party, net of tax.

Cash Flow from Operations

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2017**	September 30, 2017	December 31, 2016	**December 31, 2017**	December 31, 2016
Cash flow from operations	**26,472**	25,491	31,537	**103,873**	75,294
$ per share - basic	**0.79**	0.77	0.94	**3.12**	2.26
$ per share - diluted	**0.79**	0.77	0.94	**3.12**	2.26

In 2017, cash flow from operations increased by $28,579,000 compared to 2016. This was primarily due to an increase in revenue from oil and gas sales from higher commodity prices and to an increase in non-cash-working capital. The quarter over quarter increase in cash flow of $981,000 is primarily due to an increase in commodity prices and partially offset by both a decrease in production and an increase in production costs.

Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2016 – 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, 2017 of $476,000 (December 31, 2016 of $1,169,000). During 2016, Pine Cliff paid a management fee to the Company of $15,000 plus the reimbursement of certain administrative expenses. On April 1, 2016, the management agreement was terminated. Services previously provided by the Company included mainly executive and marketing services. All services that were performed were charged at estimated fair value. As at December 31, 2017, the Company had an account receivable from Pine Cliff of $36,000 (December 31, 2016 – $51,000).

As at December 31, 2017, the Company's CEO, Chairman of the Board and a major shareholder has loaned the Company $12,000,000 (December 31, 2016 - $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 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. Interest paid on this loan for 2017 was $274,000 (December 31, 2016 - $249,000). 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 overall debt while managing its cash flow, capital expenditures and dividend payments. The Company's net debt to twelve month trailing cash flow ratio as of December 31, 2017 was 3.1 to 1 times (versus 4.7 to 1 times at December 31, 2016). The decrease in net debt to cash flow ratio is primarily due to the $52,000,000 of cash received for the sale of a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool and improved commodity prices realized in 2017. To manage its bank debt during a period of low commodity prices the Company significantly reduced planned capital expenditures for the 2015, 2016 and 2017 fiscal years compared to 2014. Additionally, in January of 2016 the Company reduced the monthly dividend by $0.05 to $0.10 per common share. The Company will continue to assess its dividend and capital expenditures compared to cash flow from operations on a quarterly basis.

Working Capital Deficiency and Net Debt

($ 000s)	**December 31, 2017**	December 31, 2016
Working capital deficiency	**27,790**	24,921
Long-term bank debt	**292,212**	329,204
Net Debt	**320,002**	354,125

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 net debt 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 for December 31, 2017 decreased by $34,123,000 from December 2016 primarily due to the $52,000,000 received for the GORR transaction in the fourth quarter of 2017 and increased cash flow from higher commodity prices. This was offset by capital expenditures and dividends paid in the year.

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, sale of non-core assets and investments and adjustments of dividend payments. Included in the working capital deficiency at December 31, 2017 is $24,500,000 million of debt relating to the subordinated promissory note and the amount due to a related party.

Financial Risk Management

The Company has entered into physical delivery sales contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the financial statements. For more information on physical delivery contracts in place see Note 21 of the December 31, 2017 audited annual financial statements.

Capital Expenditures

During the year ended December 31, 2017, the Company incurred capital expenditures of $77,694,000 (December 31, 2016 - $40,851,000). The costs primarily relate to $60,700,000 for the drilling of 30 gross (27.9 net) Cardium operated horizontal wells and complete and tie-in 33 gross (29.6 net) wells. An additional $16,994,000 was spent on related infrastructure costs and eight gross (1.7 net) Cardium non-operated wells. In addition, $4,747,000 of asset additions were incurred for 2017 relating to the incremental Cardium assets received in the GORR transaction.

Liability Management Ratio ("LMR") Update

In 2017, 94 percent of the Company's production is from the province of Alberta. The Company currently has an LMR rating of 2.07 in Alberta and does not expect that with its current LMR there will be any regulatory impediments to completing future potential acquisitions.

Long-term Debt

Long-term debt represents the outstanding draws from the Company's bank facility as described in the notes to the Company's audited annual financial statements. As of December 31, 2017, the Company has a bank facility with a limit of $380,000,000 (December 31, 2016 - $380,000,000) that is comprised of a $330,000,000 syndicated revolving credit facility and a $50,000,000 non-syndicated revolving credit facility. Amounts drawn under this bank facility at December 31, 2017 totaled $292,212,000 (December 31, 2016 - $329,204,000). The interest rates for the year ended December 31, 2017 on the Company's Canadian prime rate loan and Banker's Acceptances are between four to six percent. The loan is revolving to April 30, 2018 with a maturity date of April 30, 2019, subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limit of the bank facility is reviewed semi-annually on or before April 30 and October 31 each year based mainly on the lender's interpretation of the Company's reserves, future commodity prices and costs. On November 1, 2017, the Company successfully renewed its available lending limit at $380,000,000.

Advances drawn under the bank facility are secured by a fixed and floating charge debenture over the assets of the Company. In the event the bank facility is 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, 2017 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, 2017		December 31, 2016	
Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**33,302,435**	**763,788**	33,143,435	760,020
Issued pursuant to the Company's share option plan	**8,361**	**143**	159,000	3,253
Transfer from contributed surplus to share capital		**46**		515
Balance, end of period	**33,310,796**	**763,977**	33,302,435	763,788

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 3,331,080 (December 31, 2016 – 3,330,244) 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 18 of the December 31, 2017 audited annual financial statements.

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 Company uses approximately 20,000 MCF per day of natural gas firm service delivery with Transcanada Pipeline. Considering approximately 90 percent of Bonterra's current natural gas production is from the solution gas in oil wells, this will reduce transportation curtailments associated with interruptible service, therefore decreasing restrictions on oil production. The terms of the various agreements expire in one to eight years.

The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 5.9 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, 2017 are as follows;

($ 000s)	2018	2019	2020	2021	2022	Thereafter	Total
Firm service commitments	1,305	1,275	1,166	1,060	999	1,535	7,340
Office lease commitements	541	506	535	535	538	521	3,176
Total	1,846	1,781	1,701	1,595	1,537	2,056	10,516

Dividend Policy

For the year ended December 31, 2017, the Company declared and paid dividends of $39,971,000 ($1.20 per share) (December 31, 2016 – $39,807,000) ($1.20 per share). Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, cash flow from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide its shareholders with a combination of sustainable growth and meaningful dividend income. Bonterra's dividend payout ratio based on cash flow from operations was 38 percent for the year ended December 31, 2017 (53 percent for the year ended December 31, 2016).

Bonterra's dividends to its shareholders are funded by a portion of cash flow from operating activities with the remaining cash flow directed towards capital spending and 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 drawdowns on Bonterra's bank facility. Bonterra intends to provide dividends to shareholders that are sustainable to the Company with consideration to its liquidity and 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.

Quarterly Financial Information

		2017		
For the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Revenue - oil and gas sales	**54,192**	46,349	52,695	49,330
Cash flow from operations	**26,472**	25,491	27,370	24,540
Net earnings (loss)	**2,096**	(3,043)	2,978	475
Per share - basic	**0.06**	(0.09)	0.09	0.01
Per share - diluted	**0.06**	(0.09)	0.09	0.01

		2016		
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	48,967	46,236	41,150	33,510
Cash flow from operations	31,537	19,219	13,392	11,146
Net loss	(1,168)	(5,830)	(5,582)	(11,555)
Per share - basic	(0.03)	(0.18)	(0.17)	(0.35)
Per share - diluted	(0.03)	(0.18)	(0.17)	(0.35)

The fluctuations in the Company's revenue and net earnings from quarter to quarter are caused by variations in production volumes, realized commodity pricing and the related impact on royalties, production, G&A and finance costs. In the first and second quarters of 2016, net earnings and cash flow were lower than most other periods due to a significant decrease in commodity prices.

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 fillings 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, 2017.

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.

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.

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. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

The Company will retrospectively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on Bonterra's comprehensive income and financial position. However, Bonterra will expand the disclosures in the notes to its financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

In January 2016, the IASB issued IFRS 16 "Leases," which replaces IAS 17 "Leases" and International Financial Reporting Interpretations Committee (IFRIC) 4 "Determining Whether an Arrangement Contains a Lease." IFRS 16 requires the recognition of lease assets and liabilities on the statement of financial position for most leases, where the entity is acting as a lessee. For lessees applying IFRS 16, the dual classification model of leases as either operating leases or finance leases no longer exists, effectively treating all leases as finance leases. Leases less than 12 months and leases of low-value assets are exempt from the balance sheet recognition requirements, and may continue to be treated as operating leases. Lessors will continue with the dual classification model for leases and the accounting for lessors remains virtually unchanged.

The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. The Company has not yet assessed the impact, if any, that the new amended standard will have on its financial statements or whether to early adopt this new requirement.

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

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

"Signed George F. Fink"

George F. Fink
Chief Executive Officer and
Chairman of the Board
March 13, 2018

"Signed Robb D. Thompson"

Robb D. Thompson
Chief Financial Officer
March 13, 2018

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, 2017 and 2016, 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, 2017 and 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

"Signed Deloitte LLP"

Chartered Professional Accountants
March 13, 2018
Calgary, Canada

STATEMENT OF FINANCIAL POSITION

As at ($ 000s)	Note	**December 31, 2017**	December 31, 2016
Assets			
Current			
Accounts receivable		**20,536**	20,774
Crude oil inventory		**794**	1,060
Prepaid expenses		**2,535**	2,529
Investments		**274**	452
		24,139	24,815
Investment in related party	7	**476**	1,169
Exploration and evaluation assets	8	**4,217**	7,073
Property, plant and equipment	9	**995,075**	1,013,133
Investment tax credit receivable	17	**8,834**	8,834
Goodwill	10	**92,810**	92,810
		1,125,551	1,147,834
Liabilities			
Current			
Accounts payable and accrued liabilities	11	**26,130**	25,236
Due to related party	12	**12,000**	12,000
Subordinated promissory note	13	**12,500**	12,500
Deferred Consideration	5,15	**1,299**	-
		51,929	49,736
Bank debt	14	**292,212**	329,204
Deferred Consideration	5,15	**14,765**	-
Decommissioning liabilities	16	**126,631**	100,941
Deferred tax liability	17	**129,754**	124,129
		615,291	604,010
Subsequent events	23		
Shareholders' equity			
Share capital	18	**763,977**	763,788
Contributed surplus		**25,533**	21,068
Accumulated other comprehensive income (loss)		**(339)**	414
Retained earnings (deficit)		**(278,911)**	(241,446)
		510,260	543,824
		1,125,551	1,147,834

See accompanying notes to these financial statements.

On behalf of the Board:

"Signed George F. Fink"

George F. Fink
Director

"Signed Rodger A. Tourigny"

Rodger A. Tourigny
Director

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31			
($ 000s, except $ per share)	Note	**2017**	2016
Revenue			
Oil and gas sales, net of royalties	19	**188,362**	160,082
Other income	20	**4,604**	233
		192,966	160,315
Expenses			
Production		**62,066**	54,503
Office and administration		**3,214**	2,584
Employee compensation		**4,535**	3,755
Finance costs	6	**19,719**	20,004
Share-option compensation		**4,511**	5,818
Depletion and depreciation	9	**89,339**	100,992
Exploration and evaluation	8	**1,566**	-
Impairment of oil and gas assets	9	**-**	2,505
		184,950	190,161
Earnings (loss) before income taxes		**8,016**	(29,846)
Taxes			
Current income tax expense (recovery)	17	**(232)**	(3,547)
Deferred income tax expense (recovery)	17	**5,742**	(2,164)
		5,510	(5,711)
Net earnings (loss) for the year		**2,506**	(24,135)
Other comprehensive income (loss)			
Unrealized gain (loss) on investments		**(871)**	2,866
Deferred taxes on unrealized (gain) loss on investments		**118**	(387)
Other comprehensive income (loss) for the year		**(753)**	2,479
Total comprehensive income (loss) for the year		**1,753**	(21,656)
Net earnings (loss) per share - basic and diluted	18	**0.08**	(0.73)
Comprehensive income (loss) per share - basic and diluted	18	**0.05**	(0.65)

See accompanying notes to these financial statements.

STATEMENT OF CASH FLOW

For the years ended December 31

($ 000s)	Note	**2017**	2016
Operating activities			
Net earnings (loss)		**2,506**	(24,135)
Items not affecting cash			
Deferred income taxes		**5,742**	(2,164)
Share-option compensation		**4,511**	5,818
Depletion and depreciation		**89,339**	100,992
Exploration and evaluation expenditures		**1,566**	-
Impairment of oil and gas assets		**-**	2,505
Gain on sale of property and equipment		**(4,233)**	(1)
Unwinding of the discount on decommissioning liabilities	16	**3,013**	2,507
Investment income		**(49)**	(18)
Interest expense		**16,706**	17,496
Change in non-cash working capital accounts:			
Accounts receivable		**(283)**	(5,266)
Crude oil inventory		**53**	(77)
Prepaid expenses		**(6)**	269
Accounts payable and accrued liabilities		**2,828**	(2,341)
Decommissioning expenditures	16	**(1,114)**	(2,795)
Interest paid		**(16,706)**	(17,496)
Cash provided by operating activities		**103,873**	75,294
Financing activities			
Increase (Decrease) of bank debt		**(36,992)**	(3,267)
Subordinated promissory note		**-**	(12,500)
Stock option proceeds		**143**	3,253
Dividends		**(39,971)**	(39,807)
Cash used in financing activities		**(76,820)**	(52,321)
Investing activities			
Investment income received		**49**	18
Exploration and evaluation expenditures	8	**(738)**	-
Property, plant and equipment expenditures	5,9	**(76,956)**	(40,851)
Proceeds on sale of property	5	**52,005**	54
Proceeds on sale of investments		**-**	10,783
Change in non-cash working capital accounts:			
Accounts payable and accrued liabilities		**(1,934)**	7,098
Accounts receivable		**521**	(75)
Cash used in investing activities		**(27,053)**	(22,973)
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

($ 000's, except number of shares outstanding)

	Numbers of common shares outstanding (Note 18)	Share Capital (Note 18)	Contributed surplus [1]	Accumulated other Comprehensive income (loss) [2]	Retained earnings (deficit)	Total shareholder's equity
January 1, 2016	33,143,435	760,020	15,765	571	(180,551)	595,805
Share-option compensation			5,818			5,818
Exercise of options	159,000	3,253				3,253
Comprehensive income (loss)				2,479	(24,135)	(21,656)
Transfer to share capital on exercise of options		515	(515)			-
Transfer on realized gain on investments				(3,047)	3,047	-
Deferred taxes on realized gain on investments				411		411
Dividends					(39,807)	(39,807)
December 31, 2016	33,302,435	763,788	21,068	414	(241,446)	543,824
Share-option compensation			4,511			4,511
Exercise of options	8,361	143				143
Transfer to share capital on exercise of options		46	(46)			-
Comprehensive income (loss)				(753)	2,506	1,753
Dividends					(39,971)	(39,971)
December 31, 2017	33,310,796	763,977	25,533	(339)	(278,911)	510,260

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

(2) Accumulated other comprehensive income is comprised of unrealized gains and losses on available-for-sale investments

See accompanying notes to these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

As at and for the year ended December 31, 2017 and 2016.

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 13, 2018.

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) 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. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

The Company will retrospectively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on Bonterra's comprehensive income and financial position. However, Bonterra will expand the disclosures in the notes to its financial statements as prescribed by IFRS 15, including disclosing the Company's disaggregated revenue streams by product type.

In January 2016, the IASB issued IFRS 16 “Leases,” which replaces IAS 17 “Leases” and International Financial Reporting Interpretations Committee (IFRIC) 4 “Determining Whether an Arrangement Contains a Lease.” IFRS 16 requires the recognition of lease assets and liabilities on the statement of financial position for most leases, where the entity is acting as a lessee. For lessees applying IFRS 16, the dual classification model of leases as either operating leases or finance leases no longer exists, effectively treating all leases as finance leases. Leases less than 12 months and leases of low-value assets are exempt from the balance sheet recognition requirements, and may continue to be treated as operating leases. Lessors will continue with the dual classification model for leases and the accounting for lessors remains virtually unchanged.

The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15. IFRS 16 is required to be adopted either retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. 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.

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 to its present location.

Production Facilities

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

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income (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) Deferred Consideration

Deferred consideration is generated when a sale of a royalty interest linked to production at a specific property occurs. Consideration is given to the specific terms of each arrangement to determine whether a disposal of an interest in the reserves of the respective property has occurred and whether the counterparty is entitled to the associated risks and rewards attributable to the property over its estimated life including the contractual terms and implicit obligations related to production, such as the holder of the royalty having the option of either being paid in cash or in kind and the associated commitments, if any, to develop future expansions or projects at the property.

Proceeds for sale of a royalty interest on petroleum properties are then attributed to two components: a payment for partial disposal of an interest in property, plant and equipment; and an upfront payment received for future extraction services that will generate future royalties. Discounted future cash flows of future development and operating costs multiplied by the royalty rate are used to derive the upfront payment received for future extraction services, which is accounted for as deferred consideration and recognized as revenue over the reserve life of the encumbered properties (as this represents the efforts incurred towards the extraction performance obligation). Upon commencement of the royalty interest the deferred consideration is depleted (recognized into revenue) using the same unit-of-production method as the depletion of the encumbered PP&E asset's carrying value.

j) 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).

k) 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.

l) 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 payments are 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.

m) 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 instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments 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.

n) 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.

o) 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.

p) 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 JUDGEMENTS

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 cash generating unit ("CGU") level. The period the Company used to project cash flows is approximately 50 years or the CGUs 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 2 on the fair value hierarchy.

For the year ended December 31, 2017, 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

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, 2017.

Bonterra Key Assumptions for Impairment

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028[2]
WTI Crude oil $US/Bbl [1]	65.44	74.51	78.24	82.45	84.10	85.78	87.49	89.24	91.03	92.85	94.71
AECO C-Spot $Mmbtu [1]	2.85	3.11	3.65	3.80	3.95	4.05	4.15	4.25	4.36	4.46	4.57
Exchange rate US$/$Cdn	0.79	0.82	0.85	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 benchmarks commodity prices are assumed to increase by 2.0% in each year after 2027 to 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 5 percent change in commodity prices or a 1 percent change in the discount rate, would result in an impairment being recorded.

Reserves Estimation

The capitalized costs of oil and gas properties and deferred consideration 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.

Deferred Consideration

Deferred consideration is incurred when the sale of a royalty interest occurs that has contractual terms or implicit obligations that requires future performance such future development costs and operating costs. Management uses judgements in determining those cash flows such as cost, inflation and the discount rate to determine the portion of proceeds that is deferred.

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. DISPOSITION

On December 20, 2017, the Company sold a two percent gross overriding royalty (GORR) on the total production from the Company's Pembina Cardium pool effective January 1, 2018. The royalty owner has the option of either being paid in cash or in kind. Consideration received on disposition was $56,747,000, comprised of $52,000,000 in cash and property, plant and equipment valued at $4,747,000.

Upon evaluating this transaction it was determined that the proceeds for the sale of the GORR were comprised of a disposal of a portion of the Pembina Cardium properties, plant and equipment and an upfront payment received for the implicit obligation of future extraction services that will generate future royalties.

The Company used discounted future cash flows of future development and operating costs multiplied by the two percent royalty rate to derive the upfront payment received for future extraction services of $16,064,000, which is being accounted for as deferred consideration and recognized as revenue over the reserve life of the Pembina

Cardium properties. The remaining proceeds of $40,683,000 were compared to the carrying value attributable to the partial disposal of property, plant and equipment of $36,457,000, resulting in a gain on disposal of $4,226,000.

6. FINANCE COSTS

A breakdown of finance costs for the years ended:

($ 000s)	**December 31, 2017**	December 31, 2016
Interest expense on bank debt	15,807	16,708
Interest expense on amounts owing to related party	274	249
Interest expense on subordinated promissory note and other	625	540
Unwinding of the fair value of decommissioning liabilities	3,013	2,507
	19,719	20,004

7. INVESTMENT IN RELATED PARTY

The investment consists of 1,034,523 (December 31, 2016 – 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.

8. EXPLORATION AND EVALUATION ASSETS

($ 000s)	
Cost and carrying amount	
Balance at January 1, 2016	7,925
Dispositions	(54)
Impairment (Note 9)	(798)
Balance at December 31, 2016	7,073
Additions	738
Transfers to property, plant and equipment	(2,028)
Expiry of exploration and evaluation assets	(1,566)
Balance at December 31, 2017	**4,217**

On December 31, 2016 Bonterra recorded a $798,000 impairment on its E&E assets in the British Columbia CGU. This was a result of a decrease in commodity price forecasts, an increase in forecasted operating costs and no currently planned future capital expenditures in this non-core area.

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, 2016	1,222,683	302,781	2,053	1,527,517
Additions	28,564	12,258	29	40,851
Adjustment to decommissioning liabilities [1]	29,706	-	-	29,706
Balance at December 31, 2016	1,280,953	315,039	2,082	1,598,074
Additions [2]	60,331	21,273	99	81,703
Transfers from exploration and evaluation assets	2,028	-	-	2,028
Adjustment to decommissioning liabilities [1]	23,791	-	-	23,791
Disposal and other	(49,040)	(11,583)	-	(60,623)
Balance at December 31, 2017	**1,318,063**	**324,729**	**2,181**	**1,644,973**

Accumulated depletion and depreciation ($ 000s)	**Oil and gas properties**	**Production facilities**	**Furniture fixtures & other equipment**	**Total property plant & equipment**
Balance at January 1, 2016	(390,485)	(90,116)	(1,529)	(482,130)
Depletion and depreciation	(84,455)	(16,452)	(85)	(100,992)
Disposal and other	(112)	-	-	(112)
Impairment	(1,366)	(341)	-	(1,707)
Balance at December 31, 2016	(476,418)	(106,909)	(1,614)	(584,941)
Depletion and depreciation	(72,586)	(16,660)	(93)	(89,339)
Disposal and other	19,353	4,812	-	24,165
Other	217	-	-	217
Balance at December 31, 2017	**(529,434)**	**(118,757)**	**(1,707)**	**(649,898)**

Carrying amounts as at: ($ 000s)				
December 31, 2016	804,535	208,130	468	1,013,133
December 31, 2017	**788,629**	**205,972**	**474**	**995,075**

(1) Adjustment to decommissioning liabilities is due to a decrease in the risk free rate and a change in estimate on decommissioning costs.
(2) Included in additions is $4,747,000 of property, plant and equipment received from the GORR sale as disclosed in Note 5.

There were no impairment losses or reversals recorded in the statement of comprehensive income (loss) for the year ended December 31, 2017.

The impairment of property, plant and equipment assets and any subsequent reversal of such impairment losses are recognized in the statement of comprehensive loss. At December 31, 2016, due to decreasing commodity price forecasts and higher operating cost forecasts in one of its CGUs, Bonterra determined that there were indicators of impairment and completed impairment test on all of its CGUs. Consequently for the year ended December 31, 2016, Bonterra recorded impairment charges totaling $1,707,000 related to the secondary British Columbia CGU. The recoverable amounts used in the impairment tests, based on fair value less cost to sell, related to this CGU were calculated using a proved plus probable reserves at a pre-discount rate of 10 percent (2016 – 10 percent). As well for the year ended December 31, 2016, Bonterra recorded impairment charges totaling $798,000 on its E&E assets, also related to its British Columbia CGU for a total impairment loss of $2,505,000. As of December 31, 2016, the recoverable amount of the British Columbia CGU is $539,000.

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, 2017 and 2016.

11. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

($ 000s)	**December 31, 2017**	December 31, 2016
Accounts payable	**19,547**	18,710
Accrued liabilities	**6,583**	6,526
	26,130	25,236

12. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2017, the Company's CEO, Chairman of the Board and a major shareholder has loaned the Company $12,000,000 (December 31, 2016 - $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 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. Interest paid on this loan during 2017 was $274,000 (December 31, 2016 - $249,000).

The Company received a management fee of $nil plus the reimbursement of certain administrative expenses for the year ended December 31, 2017 (December 31, 2016 - $15,000) for management services and office administration from Pine Cliff Energy Ltd. ("Pine Cliff"). This fee has been included in other income. On April 1, 2016, the management agreement was terminated. As at December 31, 2017, the Company had an account receivable from Pine Cliff of $36,000 (December 31, 2016 - $51,000).

Compensation for Key Management Personnel

($ 000s)	**December 31, 2017**	December 31, 2016
Compensation	**1,424**	917
Share-based payments	**1,739**	2,331
Total compensation	**3,163**	3,248

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, 2017, Bonterra had $12,500,000 (December 31, 2016 - $12,500,000) outstanding on a subordinated note to a private investor. The terms of the subordinated promissory note are that it bears interest at five percent and is repayable after thirty days' written notice by either party. Security consists of a floating demand debenture 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 $625,000 (December 31, 2016 - $540,000). On February 9, 2018 the Company repaid $2,500,000.

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, 2017, the Company has a bank facility of $380,000,000 (December 31, 2016 - $380,000,000) comprising of a $330,000,000 syndicated revolving credit facility and a $50,000,000 non-syndicated revolving credit facility. Amounts drawn under the bank facility at December 31, 2017 were $292,212,000 (December 31, 2016 - $329,204,000). Amounts borrowed under the bank facility bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 1.00 percent and 4.25 percent, depending on the type of borrowing and the Company's consolidated debt to EBITDA ratio. EBITDA is defined as net income for the period excluding finance costs, provision for current and deferred taxes, depletion and depreciation, share-option compensation, gain or loss on sale of assets and impairment of assets. The terms of the bank facility provide that the loan is revolving to April 30, 2018, with a maturity date of April 30, 2019, subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limit of the bank facility is 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. On November 1, 2017, the Company successfully renewed its available lending limit at $380,000,000.

The amount available for borrowing under the bank facility is reduced by outstanding letters of credit. Letters of credit totaling $900,000 were issued as at December 31, 2017 (December 31, 2016 - $2,990,000). Security for the bank facility consists of various and floating demand debentures totaling $750,000,000 (December 31, 2016 - $750,000,000) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

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

- The Company cannot exceed $380,000,000 in consolidated debt (excluding accounts payable and accrued liabilities). As at December 31, 2017 consolidated debt is $316,712,000.
- 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 26 percent for the current quarter.

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, 2017, the Company is in compliance with all covenants.

15. DEFERRED CONSIDERATION

Deferred consideration was recorded on the sale of a royalty interest that will be recognized from commencement of the royalty over the oil and gas reserve life of the Pembina Cardium properties. Changes to deferred consideration are as follows:

($ 000s)	**December 31, 2017**	December 31, 2016
Deferred consideration, January 1	**-**	-
Sale of a royalty interest on Pembina Cardium properties (Note 5)	**16,064**	-
Deferred consideration, end of year	**16,064**	-
Less current portion of deferred consideration	**(1,299)**	-
Non-current portion of deferred consideration	**14,765**	-

16. DECOMMISSIONING LIABILITIES

At December 31, 2017, the estimated total undiscounted amount required to settle the decommissioning liabilities was $298,111,000 (December 31, 2016- $312,436,000). The provision has been calculated assuming a 2.0 percent inflation rate (December 31, 2016 – 2.0 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 2.42 percent (December 31, 2016 – 2.95 percent).

($ 000s)	**December 31, 2017**	December 31, 2016
Decommissioning liabilities, January 1	**100,941**	71,523
Adjustment to decommissioning liabilities [1]	**23,791**	29,706
Liabilities settled during the period	**(1,114)**	(2,795)
Unwinding of the discount on decommissioning liabilities	**3,013**	2,507
Decommissioning liabilities, end of year	**126,631**	100,941

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

17. INCOME TAXES

($ 000s)	**December 31, 2017**	December 31, 2016
Deferred tax asset (liability) related to:		
Investments	**32**	(85)
Exploration and evaluation assets and property, plant and equipment	**(169,770)**	(159,670)
Investment tax credits	**(2,385)**	(2,385)
Decommissioning liabilities	**34,190**	27,251
Corporate tax losses carried forward	**10,051**	10,393
Share issue costs	**29**	281
Corporate capital tax losses carried forward	**8,699**	8,698
Unrecorded benefits of capital tax losses carried forward	**(8,699)**	(8,612)
Unrecorded benefits of successored resource related pools	**(1,901)**	-
Deferred tax asset (liability)	**(129,754)**	(124,129)

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, 2017**	December 31, 2016
Earnings (loss) before taxes	**8,016**	(29,846)
Combined federal and provincial income tax rates	**27.00%**	27.00%
Income tax provision calculated using statutory tax rates	**2,164**	(8,058)
Increase (decrease) in taxes resulting from:		
Change in statutory tax rates [1]	**-**	4
Share-option compensation	**1,218**	1,571
Realized gain on sale of investments	**-**	411
Change in unrecorded benefits of tax pools	**1,988**	-
Change in estimates and other	**140**	361
	5,510	(5,711)

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	7-100	92,306
Share issue costs	20	107
Canadian oil and gas property expenditures	10	100,746
Canadian development expenditures	30	151,862
Canadian exploration expenditures	100	8,063
Federal income tax losses carried forward(1)	100	54,221
Provincial income tax losses carried forward(2)	100	15,989
		423,294

(1) Federal income tax losses carried forward expire in the following years; 2035 - $18,151,000; 2036 - $35,853,000; 2037 - $217,000
(2) Provincial income tax losses carried forward expire in 2036 - $15,772,000; 2037 - $217,000

The Company has $8,834,000 (December 31, 2016 - $8,834,000) 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 $64,435,000 (December 31, 2016 - $64,435,000) of capital losses carried forward which can only be claimed against taxable capital gains.

18. SHAREHOLDERS' EQUITY

Authorized

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

	December 31, 2017		December 31, 2016	
Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, begginning of year	**33,302,435**	**763,788**	33,143,435	760,020
Issued pursuant to the Company's share option plan	**8,361**	**143**	159,000	3,253
Transfer from contributed surplus to share capital		**46**	-	515
Balance, end of year	**33,310,796**	**763,977**	33,302,435	763,788

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

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

	December 31, 2017	December 31, 2016
Basic shares outstanding	**33,309,578**	33,255,957
Dilutive effect of share options(1)	**2,149**	67,328
Diluted shares outstanding	**33,311,727**	33,323,285

(1) The Company did not include 2,778,000 share options (December 31, 2016 – 2,081,000) in the dilutive effect of share options calculations as these share options were anti-dilutive.

For the year ended December 31, 2017, the Company declared and paid dividends of $39,971,000 ($1.20 per share) (December 31, 2016 - $39,807,000 ($1.20 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 3,331,080 (December 31, 2016 – 3,330,244) 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 as of December 31, 2017 and changed during the period ended are presented below:

	Number of options	**Weighted average exercise price**
At January 1, 2016	2,955,500	$40.28
Options granted	935,000	25.50
Options exercised	(159,000)	20.46
Options forfeited	(152,500)	43.16
Options expired	(842,000)	58.86
At December 31, 2016	2,737,000	$30.50
Options granted	1,936,000	14.91
Options exercised[1]	(14,000)	20.46
Options forfeited	(256,000)	23.03
Options expired	(1,597,000)	32.25
At December 31, 2017	2,806,000	$19.48

(1) 7,000 options were exercised under the cashless option method, which resulted in 1,361 shares being issued in which the Company received no proceeds.

The following table summarizes information about options outstanding at December 31, 2017:

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding at December 31, 2017	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2017	Weighted-average exercise price
$ 14.00 - $ 30.00	2,698,000	1.8 years	$ 18.24	845,000	$ 25.75
30.01 - 40.00	33,000	0.4 years	33.69	25,000	34.24
40.01 - 65.00	75,000	0.1 years	57.88	75,000	57.88
$ 17.00 - $ 65.00	2,806,000	1.7 years	$ 19.48	945,000	$ 28.52

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 2017, the Company granted 1,936,000 stock options with an estimated fair value of $4,859,000 or $2.51 per option using the Black-Scholes option pricing model with the following key assumptions:

	December 31, 2017	December 31, 2016
Weighted-average risk free interest rate (%)[1]	**1.48**	0.58
Weighted-average expected life (years)	**1.5**	1.0
Weighted-average volatility (%)[2]	**47.23**	59.91
Forfeiture rate (%)	**7.68**	8.62
Weighted average dividend yield (%)	**8.18**	4.73

(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.

19. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	December 31, 2017	December 31, 2016
Oil and gas sales	**202,566**	169,863
Less:		
Crown royalties	**(10,178)**	(5,917)
Freehold, gross overriding royalties and other	**(4,026)**	(3,864)
Oil and gas sales, net of royalties	**188,362**	160,082

20. OTHER INCOME

($ 000s)	December 31, 2017	December 31, 2016
Investment income	**74**	18
Administrative income	**297**	214
Gain on sale of property and equipment	**4,233**	1
Other income	**4,604**	233

21. 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 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 had a net debt to cash flow level of 3.1:1 compared to 4.7:1 in 2016. The decrease in net debt to cash flow ratio is primarily due to a $56,747,000 sale of a royalty interest in the Pembina Cardium properties, of which $52,000,000 was received in cash (see disposition Note 5) and improved commodity prices realized in 2017. To manage its bank debt during a period of low commodity prices the Company significantly reduced planned capital expenditures for the 2016 and 2017 fiscal years. Additionally, in January of 2016 the Company reduced the monthly dividend by $0.05 to $0.10 per common share.

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, 2017 are as follows:

($ 000s)	
Bank debt	292,212
Accounts payable and accrued liabilities	26,130
Due to related party	12,000
Subordinated promissory note	12,500
Current assets	(24,139)
Net debt	318,703
Cash flow from operations	103,873
Net debt ratio	3.1

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. The Company has assumed the risk in respect of commodity prices, except for a small portion of physical delivery sales contracts to manage commodity risk on the Company's higher operating cost areas. These contracts are considered normal sales contracts and are not recorded at fair value in the financial statements.

The Company has entered into the following physical delivery sales contracts during the year ended December 31, 2017:

Product	Type of contract	Volume	Term	Contract price
Oil	Fixed price - WTI[(1)]	500 BBL/day	October 1 to December 31 2017	$51.90 US/BBL
Oil	Basis Differential WTI [(1)(3)]	500 BBL/day	November 1 to November 30, 2017	$(2.00) US/BBL
Oil	Basis Differential WTI [(1)(3)]	500 BBL/day	December 1 to December 31, 2017	$(3.10) US/BBL
Oil	Fixed price - WTI[(1)]	500 BBL/day	January 1 to March 31, 2018	$57.19 US/BBL
Oil	Basis Differential WTI [(1)(3)]	500 BBL/day	January 1 to March 31, 2018	$(2.80) US/BBL

(1) WTI refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States.
(2) "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.
(3) Basis differential is the difference between WTI and MSW steam index.

The Company has entered into the following physical delivery sales contracts subsequent to December 31, 2017:

Product	Type of contract	Volume	Term	Contract price
Oil	Fixed price - WTI	500 BBL/day	January 1 to June 30, 2018	$59.55 US/BBL
Gas	Costless physical gas collar - AECO[(1)]	5000 GJ/day	April 1 to June 30, 2018	Floor price $0.80 $Cdn/GJ Ceiling price $1.23 $Cdn/GJ

(1) AECO refers to Alberta Energy Company, a grade or heating content of natural gas used as benchmark pricing in Alberta, Canada.

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 $330,000,000 syndicated revolving operating line, $50,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $12,500,000 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 five 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 $2,221,000.

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 U.S. currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

Credit risk

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

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

Of the $20,536,000 accounts receivable balance at December 31, 2017 (December 31, 2016 - $20,774,000) over 84 percent (2016 – 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, 2017, 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, 2017, approximately $1,434,000 or 7 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2016 - $2,166,000 or 10 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, 2017 is $1,146,000 (December 31, 2016 - $354,000) 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	26,130	-
Due to related parties	Yes - Liability	12,000	-
Suboridinated promissory note	Yes - Liability	12,500	-
Bank Debt	Yes - Liability	-	292,212
Firm service commitments	No	1,305	6,035
Office lease commitments	No	541	2,635
Total		52,476	300,882

22. 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 eight years.

The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 5.9 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, 2017 are as follows:

($ 000s)	2018	2019	2020	2021	2022	Thereafter	Total
Firm service commitments	1,305	1,275	1,166	1,060	999	1,535	7,340
Office lease commitements	541	506	535	535	538	521	3,176
Total	1,846	1,781	1,701	1,595	1,537	2,056	10,516

23. SUBSEQUENT EVENTS

i) Dividends

Subsequent to December 31, 2017, the Company declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 2, 2018	January 15, 2017	0.10	January 31, 2018
February 1, 2018	February 15, 2018	0.10	February 28, 2018
March 1, 2018	March 15, 2018	0.10	March 29, 2018

Corporate Information

Board of Directors
G. F. Fink - Chairman
G. J. Drummond
R. M. Jarock
R. A. Tourigny
A. M. Walsh

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, Senior VP, Business Development

Registrar and Transfer Agent
Odyssey Trust Company

Auditors
Deloitte LLP

Solicitors
Borden Ladner Gervais LLP

Bankers
CIBC
National Bank of Canada
The Toronto Dominion Bank
Alberta Treasury Branches
Business Development Bank of Canada

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