



For the year ended  
December 31, 2018

TSX: **BNE**  
www.bonterraenergy.com

## ANNUAL HIGHLIGHTS

As at and for the year ended (\$000s except \$ per share)	December 31, 2018	December 31, 2017	December 31, 2016	
<b>FINANCIAL</b>				
Revenue - realized oil and gas sales	<b>223,388</b>	202,566	169,863	
Funds flow <sup>(1)</sup>	<b>107,251</b>	102,444	96,305	
Per share - basic and diluted	<b>3.22</b>	3.08	2.90	
Dividend payout ratio	<b>34%</b>	39%	41%	
Cash flow from operations	<b>115,963</b>	103,873	75,294	
Per share - basic and diluted	<b>3.48</b>	3.12	2.26	
Dividend payout ratio	<b>32%</b>	38%	53%	
Cash dividends per share	<b>1.11</b>	1.20	1.20	
Net earnings (loss)	<b>7,167</b>	2,506	(24,135)	
Per share - basic and diluted	<b>0.22</b>	0.08	(0.73)	
Capital expenditures	<b>78,737</b>	82,441	40,797	
Disposition	-	56,752 <sup>(2)</sup>	-	
Total assets	<b>1,103,833</b>	1,125,551	1,147,834	
Working capital deficiency	<b>30,281</b>	27,790	24,921	
Long-term debt	<b>298,660</b>	292,212	329,204	
Shareholders' equity	<b>483,970</b>	510,260	543,824	
<b>OPERATIONS</b>				
Oil	-bbl per day	<b>8,119</b>	7,907	7,942
	-average price (\$ per bbl)	<b>65.51</b>	59.30	49.46
NGLs	-bbl per day	<b>995</b>	905	894
	-average price (\$ per bbl)	<b>40.32</b>	31.47	19.93
Natural gas	-MCF per day	<b>24,549</b>	24,087	22,888
	-average price (\$ per MCF)	<b>1.63</b>	2.40	2.34
Total barrels of oil equivalent per day (BOE) <sup>(3)</sup>	<b>13,206</b>	12,827	12,650	

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

<sup>(2)</sup> For 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 was 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).

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

## QUARTERLY HIGHLIGHTS

2018

As at and for the periods ended (\$ 000s except \$ per share)	Q4	Q3	Q2	Q1
<b>Financial</b>				
Revenue - oil and gas sales	<b>34,988</b>	63,817	67,458	57,124
Funds flow <sup>(1)</sup>	<b>10,618</b>	31,032	37,642	27,959
Per share - basic and diluted	<b>0.32</b>	0.93	1.13	0.84
Dividend payout ratio	<b>66%</b>	32%	27%	36%
Cash flow from operations	<b>20,509</b>	33,669	31,908	29,877
Per share - basic and diluted	<b>0.61</b>	1.01	0.96	0.90
Dividend payout ratio	<b>34%</b>	30%	31%	33%
Cash dividends per share	<b>0.21</b>	0.30	0.30	0.30
Net earnings (loss)	<b>(10,909)</b>	5,756	8,925	3,395
Per share - basic and diluted	<b>(0.33)</b>	0.17	0.27	0.10
Capital expenditures	<b>4,785</b>	18,814	18,970	36,168
Total assets	<b>1,103,833</b>	1,137,748	1,147,501	1,142,670
Working capital deficiency	<b>30,281</b>	35,319	27,069	46,630
Long-term debt	<b>298,660</b>	293,197	303,413	291,994
Shareholders' equity	<b>483,970</b>	500,507	503,979	504,240
<b>Operations</b>				
Oil (barrels per day)	<b>7,756</b>	7,949	8,743	8,034
Average price (\$ per bbl)	<b>38.96</b>	77.20	76.51	67.78
NGLs (barrels per day)	<b>1,025</b>	1,070	984	900
Average price (\$ per bbl)	<b>34.73</b>	43.95	43.69	38.70
Natural gas (MCF per day)	<b>24,045</b>	24,144	25,317	24,701
Average price (\$ per MCF)	<b>1.77</b>	1.37	1.16	2.24
Total BOE per day	<b>12,789</b>	13,043	13,946	13,051

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

<sup>(2)</sup> 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.

## REPORT TO SHAREHOLDERS

Bonterra Energy Corp. (“Bonterra” or the “Company”) continued to realize operational and financial success in 2018, despite a challenging year overall for the resource industry in Canada. In addition to ongoing regulatory and operational requirements that face Canadian oil and natural gas producers, the Federal and Alberta governments implemented policies and regulations pertaining to the transportation of oil and natural gas to end consumers of these important resources. As a result of these changes, Canadian producers are finding it increasingly difficult to remain competitive with other global energy producers.

### Bonterra 2018 Highlights

- Overall, the Company’s results were materially impacted by the severe deterioration in oil prices that occurred in the fourth quarter. During the last three months of 2018, Bonterra’s Canadian realized price for crude oil averaged \$38.96 per bbl compared to an average Canadian realized price of \$73.83 per bbl through the first nine months of the year.
- Revenue from oil and gas sales in 2018 increased to \$223 million from \$203 million in 2017.
- Funds flow in 2018 increased to \$107 million (\$3.22 per share basic and diluted) from \$102 million in 2017 (\$3.12 per share basic and diluted).
- Net earnings in 2018 increased to \$7 million from \$2.5 million in 2017.
- Average annual production volumes increased to 13,206 per BOE compared to 12,827 per BOE in 2017.
- Long-term bank debt increased modestly to \$299 million in 2018 compared to \$293 million in 2017.
- To prudently manage bank debt during low realized oil prices, the Company adjusted the monthly dividend in December 2018 to \$0.01 per common share from \$0.10 per common share.

### Bonterra’s Advantages

Going forward, the Company will continue to direct its efforts to becoming a meaningful dividend paying entity while offering modest production growth during periods of weak or volatile commodity prices, rather than risk financial flexibility through an aggressive growth strategy.

During Q4 2018, the Company’s all-in costs, including royalties, operating costs, general and administration expenses and interest on debt totaled \$21.67 per BOE, down over 19 percent from \$26.87 per BOE in Q3 2018, resulting in the Company having one of the lowest all-in cost structures in the industry.

By owning the majority of its facilities and gas plants, Bonterra can maintain better control of its cost structure through the processing of its oil, natural gas liquids and natural gas. At approximately 22 percent, the Company has one of the lowest decline rates among its peer group, which contributes to sustainable production for the long-term.

### Outlook

For 2019, Bonterra has set its capital expenditures budget between \$57 to \$77 million, which will be directed largely to drilling wells primarily in the Pembina oil field in Alberta. This budget is designed to be flexible and may be modified during the year depending on commodity prices.

Going forward, Bonterra will continue to focus on operational efficiencies and financial discipline to maximize returns for shareholders. Unfortunately, as recent history has demonstrated, commodity prices can be negatively affected by political decisions. With this understanding, the Company and its Board will continue to manage Bonterra’s

business cautiously in the context of a volatile commodity price environment that is also plagued by increased provincial and federal political uncertainty.

The Board of directors and management wish to thank all of the Company's employees and consultants for their continued contributions and a sincere thank you to all shareholders for their ongoing trust in Bonterra during these volatile times.

Thank you once again for your continued support.

A handwritten signature in dark ink, appearing to read "G. Fink", written in a cursive style.

George F. Fink  
Chief Executive Officer and Chairman of the Board

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated March 12, 2019 is a review of the operations and current financial position for the year ended December 31, 2018 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 statement 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 COMPARISONS

As at and for the year ended (\$000s except \$ per share)	December 31, 2018	December 31, 2017	December 31, 2016	
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Revenue - realized oil and gas sales	<b>223,388</b>	202,566	169,863	
Cash flow from operations	<b>115,963</b>	103,873	75,294	
Per share - basic and diluted	<b>3.48</b>	3.12	2.26	
Payout ratio	<b>32%</b>	38%	53%	
Cash dividends per share	<b>1.11</b>	1.20	1.20	
Net earnings (loss)	<b>7,167</b>	2,506	(24,135)	
Per share - basic and diluted	<b>0.22</b>	0.08	(0.73)	
Capital expenditures, net of disposition	<b>78,737</b>	82,441	40,797	
Disposition	-	56,752 <sup>(1)</sup>	-	
Total assets	<b>1,103,833</b>	1,125,551	1,147,834	
Working capital deficiency	<b>30,281</b>	27,790	24,921	
Long-term debt	<b>298,660</b>	292,212	329,204	
Shareholders' equity	<b>483,970</b>	510,260	543,824	
<b>OPERATIONS</b>				
Oil	-bbl per day	<b>8,119</b>	7,907	7,942
	-average price (\$ per bbl)	<b>65.51</b>	59.30	49.46
NGLs	-bbl per day	<b>995</b>	905	894
	-average price (\$ per bbl)	<b>40.32</b>	31.47	19.93
Natural gas	-MCF per day	<b>24,549</b>	24,087	22,888
	-average price (\$ per MCF)	<b>1.63</b>	2.40	2.34
<b>Total barrels of oil equivalent per day (BOE)</b>		<b>13,206</b>	12,827	12,650

<sup>(1)</sup> 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 was 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

2018				
As at and for the periods ended				
(\$ 000s except \$ per share)	Q4	Q3	Q2	Q1
<b>Financial</b>				
Revenue - oil and gas sales	34,988	63,817	67,458	57,124
Cash flow from operations	20,509	33,669	31,908	29,877
Per share - basic and diluted	0.61	1.01	0.96	0.90
Payout ratio	34%	30%	31%	33%
Cash dividends per share	0.21	0.30	0.30	0.30
Net earnings (loss)	(10,909)	5,756	8,925	3,395
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Oil (barrels per day)	7,756	7,949	8,743	8,034
NGLs (barrels per day)	1,025	1,070	984	900
Natural gas (MCF per day)	24,045	24,144	25,317	24,701
Total BOE per day	12,789	13,043	13,946	13,051

2017				
As at and for the periods ended				
(\$ 000s except \$ per share)	Q4	Q3	Q2	Q1
<b>Financial</b>				
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	14,121	19,416	30,129
Disposition	56,752 <sup>(1)</sup>	-	-	-
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
<b>Operations</b>				
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

<sup>(1)</sup> 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 was 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).

## Business Environment and Sensitivities

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials, production volumes 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.

	Q4-2018	Q3-2018	Q2-2018	Q1-2018	Q4-2017	Q3-2017	Q2-2017	Q1-2017
Crude oil								
WTI (U.S.\$/bbl)	<b>58.81</b>	69.50	67.88	62.87	55.40	48.30	48.28	51.91
WTI to MSW Stream Index								
Differential (U.S.\$/bbl) <sup>(1)</sup>	<b>(26.30)</b>	(6.83)	(5.45)	(5.89)	(1.14)	(2.89)	(2.26)	(3.60)
Foreign exchange								
U.S.\$ to Cdn\$	<b>1.3215</b>	1.3070	1.2911	1.2651	1.2717	1.2524	1.3447	1.3230
Bonterra average realized								
oil price (Cdn\$/bbl)	<b>38.96</b>	77.20	76.51	67.78	65.16	53.48	58.27	60.63
Natural gas								
AECO (Cdn\$/mcf)	<b>1.55</b>	1.19	1.18	2.07	1.68	1.45	2.77	2.68
Bonterra average realized								
gas price (Cdn\$/mcf)	<b>1.77</b>	1.37	1.16	2.24	1.90	1.81	3.03	2.97

<sup>(1)</sup>This differential accounts for the majority of the difference between WTI and Bonterra's average realized price (before quality adjustments and foreign exchange).

The overall volatility in Bonterra's average realized commodity prices 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.

WTI benchmark pricing which had been steadily increasing from the low of US\$30.62 per bbl in February of 2016, decreased in the fourth quarter of 2018, and is currently trading around US\$55.00 per barrel. Uncertainties around both global supply and global demand have resulted in a volatile pricing environment for crude. Global trade issues, in particular between US and China, have created concern that global demand growth may weaken in 2019. Regarding supply, there is uncertainty whether crude from shale oil growth in the US, will outpace cuts that were recently agreed to by OPEC and several non-OPEC nations. In Canada, the volatility is even greater as a shortage of pipeline capacity and recent refinery maintenance has led to material apportionment on feeder and export pipelines. In Q4 2018, this has led to incremental price weakness for Canadian light oil, making Canadian oil much cheaper relative to US and global benchmarks.

There is some relief in sight for Canadian crude grades. Presently, the Alberta Governments mandatory crude curtailments have resulted in a significant narrowing of the differentials for all grades of Canadian crude. This has brought Canadian prices more in line with global markets. Completion of any of the pipeline expansion projects or increasing the country's export capabilities by expanding capacity on existing lines may have a positive effect on the movement and pricing of Canadian barrels. In addition to pipelines, industry can utilize rail to ship crude, which has grown substantially to reach record highs through late 2018 and into 2019. An additional 100,000 barrels per day of crude by rail is expected to commence during Q1 2019. While it is believed rail will help alleviate some backlog of oil and narrow the gap between Canadian and US prices, it is still insufficient to permanently offset the transportation restrictions caused by a lack of pipeline capacity.

The AECO benchmark price for natural gas increased in the fourth quarter of 2018 and has further strengthened in the first quarter of 2019 due to extreme cold winter weather. With storage levels below the five-year average, there is the potential to see price appreciation over 2018. However, it is expected that prices will remain volatile for the remainder of 2019. The final investment decision by LNG Canada may provide positive torque to the negative sentiment towards western Canadian-based natural gas producers. While the project does not impact near-term supply/demand imbalances, it does have positive implications for the longer term.

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<sup>(1)</sup>

Impact on cash flow	Change (\$)	\$000s	\$ per share <sup>(2)</sup>
Realized crude oil price (\$/bbl)	1.00	2,606	0.08
Realized natural gas price (\$/mcf)	0.10	901	0.03
U.S.\$ to Canadian \$ exchange rate	0.01	1,173	0.04

<sup>(1)</sup> This analysis uses current royalty rates, annualized estimated average production of 12,900 BOE per day and no changes in working capital

<sup>(2)</sup> Based on annualized basic weighted average shares outstanding of 33,388,796

## 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 90 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, 2018, Bonterra has identified a horizontal drilling inventory of approximately 700 net Cardium locations (for more information and advisories regarding drilling locations, please refer to Drilling Locations within the Forward Looking Information section). Bonterra has also identified additional drilling locations in other formations within Alberta, Saskatchewan and British Columbia.

The Company averaged 13,206 BOE per day for 2018, which was a corporate production record and fell within its annual production guidance and was a three percent increase from 2017 of 12,827 BOE per day. The Company also experienced a 12 percent increase in cash flow from operations primarily due to a seven percent increase in realized commodity prices, combined with higher production volumes. Higher production volumes can be attributed to the Company's first quarter capital program and well reactivation program which targeted previously non-producing wells.

The Company averaged 12,789 BOE per day for the fourth quarter of 2018, compared to 13,043 BOE per day for the third quarter of 2018. Decrease in production quarter-over-quarter was the result of fewer new wells coming on production in the current quarter and Bonterra's decision to perform less well maintenance work on wells due to extremely high differentials for Canadian crude oil.

Differentials on Canadian sweet crude oil averaged US\$26.30 per bbl in the fourth quarter of 2018 with December reaching US\$34.80 per bbl due to a lack of pipeline capacity. In order to combat the glut of Canadian crude oil inventory and the restricted pipeline capacity, both of which caused large discounts on Canadian crude, the provincial government of Alberta has implemented mandatory production cuts per operator, which led to a drop in the Canadian sweet crude oil differential down to US\$4.85 per bbl in Q1 2019. Under this mandated curtailment, the first 10,000 bbls per day of crude oil are exempt. Since Bonterra operates most of its production and the Company's oil production is below the exemption, the required cuts are expected to have a minimal impact on Bonterra's overall production levels. The Company has set its 2019 annual production guidance to be between 12,600 to 13,200 BOE per day (of which approximately 62 percent would be sweet crude oil), as production volumes will vary depending on the level of capital invested, which will be determined based on commodity prices.

In 2018, the Company invested a total of \$78.7 million, less than the \$80 million annual capital budget projected in Bonterra's Q3 2018 report. Of the total amount, \$3.7 million was directed to acquire exploration and evaluation (E&E) assets as well as incremental Cardium oil and gas assets. The capital program was weighted towards the first five

months of 2018 to maximize production prior to spring breakup when lease accessibility declines. Approximately \$65 million was allocated to drill, complete, equip and tie-in 34 gross (28.0 net) wells. The remaining \$10 million was spent on infrastructure, recompletions and other capital expenditures. The annual capital budget for 2019 has been set within a range of \$57 to \$77 million, which will be dependent on Canadian realized pricing per BOE.

On October 30, 2018, following the semi-annual review of its bank facility, the Company's borrowing base was successfully renewed at \$380 million. The bank facility is comprised of a \$330 million syndicated revolving credit facility, and a \$50 million non-syndicated revolving credit facility. The revolving period on the bank facility expires on April 29, 2019, with a maturity date of April 30, 2020, subject to an annual review. As at December 31, 2018, Bonterra had \$299 million drawn on the \$380 million bank facility. These credit facilities provide the Company with sufficient liquidity and financial flexibility to execute its business plan and Bonterra remains committed to debt repayment in the interests of maintaining a strong balance sheet.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending, 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 daily production volumes, average realized prices, and average operating costs per unit of production. Disclosure of these key performance measures can be found in this MD&A and/or previous interim or annual MD&A disclosures.

## Drilling

	Three months ended						Year ended			
	December 31, 2018		September 30, 2018		December 31, 2017		December 31, 2018		December 31, 2017	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>								
Crude oil horizontal-operated	-	-	7	6.9	5	4.4	<b>27</b>	<b>26.9</b>	30	27.9
Crude oil horizontal-non-operated	<b>2</b>	<b>0.3</b>	3	0.6	2	0.2	<b>7</b>	<b>1.1</b>	8	1.7
<b>Total</b>	<b>2</b>	<b>0.3</b>	10	7.5	7	4.6	<b>34</b>	<b>28.0</b>	38	29.6
Success rate	<b>100%</b>		100%		100%		<b>100%</b>		100%	

<sup>(1)</sup> "Gross" wells are the number of wells in which Bonterra has a working interest.

<sup>(2)</sup> "Net" wells are the aggregate number of wells obtained by multiplying each gross well by Bonterra's percentage of working interest.

During 2018, the Company drilled, completed, equipped and placed on production 27 gross (26.9 net) operated wells.

In addition, 7 gross (1.1 net) non-operated wells were drilled, completed, equipped and placed on production during 2018.

## Production

	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Crude oil (barrels per day)	<b>7,756</b>	7,949	7,766	<b>8,119</b>	7,907
NGLs (barrels per day)	<b>1,025</b>	1,070	963	<b>995</b>	905
Natural gas (MCF per day)	<b>24,045</b>	24,144	24,466	<b>24,549</b>	24,087
Average BOE per day	<b>12,789</b>	13,043	12,807	<b>13,206</b>	12,827

Annual production increased in 2018 compared to 2017, primarily due to a successful drilling program during the first five months which led to higher second quarter production volumes. With increased crude oil prices, Bonterra placed a strong focus on bringing new wells on production earlier in the year. As a result, 67 percent of the Company's 27 (26.9 net) wells placed on production during the year were brought on by the end of April. This is a substantial increase relative to the prior year, during which 45 percent of the 33 (29.6 net) wells that were placed on production in that year were brought on before the end of April, 2017.

In Q4 2018, production volumes decreased by 254 BOE per day to 12,789 BOE per day compared to Q3 2018. This was primarily due to a planned reduction in capital spending related to the severe decline in realized oil prices, which

resulted in fewer new wells being placed on production and a reduction in maintenance spending on wells that were off-line.

## Cash Netback

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

\$ per BOE	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Production volumes (BOE)	<b>1,176,545</b>	1,199,929	1,178,212	<b>4,820,186</b>	4,681,773
Gross production revenue	<b>29.74</b>	53.18	46.09	<b>46.34</b>	43.29
Royalties	<b>(3.17)</b>	(6.17)	(3.37)	<b>(4.94)</b>	(3.03)
Production costs	<b>(14.23)</b>	(16.31)	(14.79)	<b>(14.49)</b>	(13.26)
Field netback	<b>12.34</b>	30.70	27.93	<b>26.91</b>	27.00
General and administrative	<b>(1.19)</b>	(1.45)	(1.37)	<b>(1.51)</b>	(1.66)
Interest and other	<b>(3.08)</b>	(2.94)	(3.58)	<b>(3.16)</b>	(3.49)
Cash netback	<b>8.07</b>	26.31	22.98	<b>22.24</b>	21.85

Cash netbacks increased in 2018 compared to 2017 primarily due to increased commodity prices. This increase was partially offset by an increase in royalty rates for the two percent gross overriding royalty (GORR) on the Pembina Cardium pool assets that was effective January 1, 2018 and an increase in production costs.

Quarter-over-quarter, cash netbacks decreased due to extremely high differentials on sweet crude oil of \$26.30 per bbl for the quarter, which significantly reduced Bonterra's realized prices for crude oil. This was partially offset by lower royalty costs from decreased commodity prices and decreased production costs from reduced maintenance compared to Q3 2018. The Company also successfully reduced its all-in costs (royalties, production costs, general and administrative and interest) to \$21.67 per BOE in Q4 compared to \$26.87 per BOE in Q3.

## Oil and Gas Sales

Revenue - oil and gas sales (\$ 000s)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Crude oil	<b>27,801</b>	56,457	46,506	<b>194,137</b>	171,415
NGL	<b>3,273</b>	4,325	3,422	<b>14,645</b>	10,242
Natural gas	<b>3,914</b>	3,035	4,264	<b>14,606</b>	20,909
	<b>34,988</b>	63,817	54,192	<b>223,388</b>	202,566
Average realized prices:					
Crude oil (\$ per barrel)	<b>38.96</b>	77.20	65.16	<b>65.51</b>	59.30
NGLs (\$ per barrel)	<b>34.73</b>	43.95	39.12	<b>40.32</b>	31.47
Natural gas (\$ per MCF)	<b>1.77</b>	1.37	1.90	<b>1.63</b>	2.40
Average (\$ per BOE)	<b>29.74</b>	53.18	46.09	<b>46.34</b>	43.29
Average BOE per day	<b>12,789</b>	13,043	12,807	<b>13,206</b>	12,827

Revenue from oil and gas sales increased by \$20,822,000, or 10 percent, compared to the same period a year ago. The increase in oil and gas sales was primarily driven by higher production and commodity prices for oil and NGLs in the first ten months of the year. The quarter-over-quarter decrease in oil and gas sales was primarily due to a decrease in realized crude oil prices stemming from extremely high differentials on Canadian crude oil in November (US\$26.70 per bbl) and December (US\$34.80 per bbl), a lower WTI price for crude oil and reduced production volumes.

The Company's product split on a revenue basis for 2018 year is weighted approximately 94 percent crude oil and NGLs.

## Royalties

(\$ 000s)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Crown royalties	2,476	4,784	2,913	15,157	10,178
Freehold, gross overriding and other royalties	1,254	2,616	1,061	8,665	4,026
<b>Total royalties</b>	<b>3,730</b>	<b>7,400</b>	<b>3,974</b>	<b>23,822</b>	<b>14,204</b>
Crown royalties - percentage of revenue	7.1	7.5	5.4	6.8	5.0
Freehold, gross overriding and other royalties - percentage of revenue	3.6	4.1	2.0	3.9	2.0
Royalties - percentage of revenue	10.7	11.6	7.4	10.7	7.0
Royalties \$ per BOE	3.17	6.17	3.37	4.94	3.03

Royalties paid by the Company consist of crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and other royalties. Total royalties on a per BOE basis increased by \$1.91 per BOE for 2018 compared to 2017. The increase in royalties is primarily due to the two percent GORR transaction on the Pembina Cardium pool assets along with an overall increase in commodity prices. The quarter-over-quarter decrease in royalties of \$3.00 per BOE was due to a decrease in crude oil prices.

## Production Costs

(\$ 000s except \$ per BOE)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Production costs	16,746	19,572	17,428	69,861	62,066
\$ per BOE	14.23	16.31	14.79	14.49	13.26

Production costs for 2018 increased by \$1.23 per BOE compared to 2017. Higher costs are attributable to the deployment of additional service rigs during the first quarter of 2018 in order to reactivate non-producing down wells and take advantage of higher commodity prices as well as avoid pending road bans that typically occur due to wet weather during spring break-up. Year-over-year, during 2018 Bonterra experienced an increase in road and lease maintenance and equipment repair programs compared to the previous year. In addition, the Company experienced higher power costs following the retirement of coal-fired power generation facilities in Alberta effective April 1, 2018.

Production costs for Q4 2018 decreased by \$2.08 per BOE compared to the previous quarter. The decrease was primarily due to a reduction on road and lease maintenance and service rig operations due to extremely low commodity prices.

## Other Income

(\$ 000s)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Investment income	17	21	33	65	74
Administrative income	43	39	108	176	297
Deferred consideration	302	332	-	1,362	-
Gain on sale of property	-	-	4,233	-	4,233
	<b>362</b>	<b>392</b>	<b>4,374</b>	<b>1,603</b>	<b>4,604</b>

In the fourth quarter of 2017, Bonterra sold a two percent overriding royalty interest on 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 plus 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, of which \$1,362,000 was recognized in 2018.

The market value of the investments held by the Company at December 31, 2018 was \$374,000 (December 31, 2017 - \$750,000). The carrying value decreased due to a reduction in the investments' carrying value. There were no dispositions for the year ended December 31, 2018 or 2017. Dispositions that result in a gain or loss on sale are 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			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Employee compensation expense	696	1,202	1,007	4,633	4,535
Office and administrative expense	699	534	611	2,645	3,214
Total G&A expense	1,395	1,736	1,618	7,278	7,749
\$ per BOE	1.19	1.45	1.37	1.51	1.66

The increase of \$98,000 in employee compensation expense for 2018 compared to 2017 is primarily due to a higher bonus accrual from increased earnings before income taxes. Quarter-over-quarter, employee compensation decreased due to a reduction in the bonus accrual from decreased earnings before income taxes in Q4 2018. 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 administrative expenses for 2018 decreased by \$569,000 compared to 2017 primarily due to a reduction in consulting fees and a decrease in the allowance for doubtful accounts expense.

## Finance Costs

(\$ 000s except \$ per BOE)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Interest on long-term debt	3,444	3,352	4,129	14,560	15,807
Other interest	239	230	235	905	899
Interest expense	3,683	3,582	4,364	15,465	16,706
\$ per BOE	3.13	2.99	3.70	3.21	3.57
Unwinding of the discounted value of decommissioning liabilities	762	789	761	3,069	3,013
Total finance costs	4,445	4,371	5,125	18,534	19,719

Interest on long-term debt decreased in 2018 compared to 2017 due to the Company carrying average long-term debt that was lower by \$38,500,000 due to the proceeds received for the two percent GORR transaction on the Pembina Cardium pool assets in December 2017. Interest rates for the current quarter are determined based on the trailing quarter and calculated by taking the ratio of total debt (excluding accounts payable and accrued liabilities) to 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 primarily to amounts paid to a related party (see related party transactions) and a \$10,000,000 subordinated promissory note from a private investor. On January 2, 2019 the Company repaid \$2,500,000 of the subordinated promissory note. For more information about the subordinated promissory note, refer to Note 12 of the December 31, 2018 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 \$2,268,000.

## Share-Option Compensation

(\$ 000s)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Share-option compensation	449	753	604	2,710	4,511

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 \$1,801,000 from a year ago. This decline is due to most of the options issued in 2016 (that were fully amortized in 2017) having a higher share price volatility than the options issued in the fourth quarter of 2017 (which are amortized in 2018). Quarter-over-quarter share-option compensation decreased due to the majority of the 2017 share-options being fully amortized at the end of the third quarter of 2018 and the majority of the current year options being issued in December.

Based on the outstanding options as of December 31, 2018, the Company has an unamortized expense of \$2,086,000, of which \$1,967,000 will be recorded for 2019; \$90,000 for 2020; and \$29,000 thereafter. For more information about options issued and outstanding, refer to Note 17 of the December 31, 2018 audited annual financial statements.

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

(\$ 000s)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Depletion and depreciation	23,189	22,288	22,912	91,453	89,339
Exploration and evaluation	-	-	1,566	291	1,566

The provision for depletion and depreciation increased in 2018 compared to 2017 due to increased production volumes and higher capital spending. The quarter-over-quarter decrease in depletion and depreciation is due to a decrease in the December 31, 2018 proved plus probable developed reserves, which was partially offset by lower production volumes in Q4 2018.

The E&E expense related to expired leases.

There were no impairment provisions recorded for the year ended December 31, 2018 and 2017.

## Taxes

The Company recorded income tax expense of \$3,875,000 (2017 – \$5,510,000). The decrease in income tax expense is due to a decrease in the change in unrecorded benefits on successored resource related tax pools.

For additional information regarding income taxes, see Note 16 of the December 31, 2018 audited annual financial statements.

## Net Earnings (Loss)

(\$ 000s except \$ per share)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Net earnings (loss)	(10,909)	5,756	2,096	7,167	2,506
\$ per share - basic	(0.33)	0.17	0.06	0.22	0.08
\$ per share - diluted	(0.33)	0.17	0.06	0.22	0.08

Net earnings for 2018 increased by \$4,661,000 compared to 2017. The increase in net earnings was mainly due to increased commodity prices for oil and NGLs and production volumes. The increase in net earnings was partially offset by an increase in royalties and production costs.

The quarter-over-quarter decrease in net earnings was mainly due to a decrease in realized crude oil prices.

## Other Comprehensive Income (Loss)

Other comprehensive income for 2018 consists of an unrealized loss before tax on investments (including investment in a related party) of \$376,000 relating to a decrease in the investments' fair value (December 31, 2017 – unrealized loss of \$871,000). 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

(\$ 000s except \$ per share)	Three months ended			Year ended	
	December 31, 2018	September 30, 2018	December 31, 2017	December 31, 2018	December 31, 2017
Cash flow from operations	20,509	33,669	26,472	115,963	103,873
\$ per share - basic	0.61	1.01	0.79	3.48	3.12
\$ per share - diluted	0.61	1.01	0.79	3.48	3.12

In 2018, cash flow from operations increased by \$12,090,000 compared to the same period a year ago. This was primarily due to an increase in revenue from oil and gas sales, which was partially offset by an increase in royalties and production costs.

The quarter-over-quarter decrease in cash flow of \$13,160,000 is primarily due to a decrease in oil and gas sales, which was partially offset by an increase in non-cash working capital and a decrease in royalties and production costs.

## Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2017 – 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, 2018 of \$258,000 (December 31, 2017 of \$476,000). The Company provides marketing services for Pine Cliff. All services that were performed were charged at estimated fair value. As at December 31, 2018, the Company had an account receivable from Pine Cliff of \$71,000 (December 31, 2017 – \$36,000).

As at December 31, 2018, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company \$12,000,000 (December 31, 2017 - \$12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8<sup>th</sup> 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 in 2018 was \$362,000 (December 31, 2017 - \$274,000). This loan results in a 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, 2018 was 2.8 to 1 times (versus 3.1 to 1 times at December 31, 2017). The reduction in net debt to cash flow ratio is due to an

increase in cash flow and \$52 million received on December 20, 2017 for the sale of a royalty interest in the Pembina Cardium properties. Net debt increased by \$8,939,000 in 2018 due to significantly decreased cash flow in the fourth quarter largely caused by depressed realized Canadian crude oil prices related to differentials from WTI of over US\$34 per bbl on light sweet crude. This increase in net debt was partially offset by increased production and commodity prices realized in the first ten months of 2018 and a reduction in Bonterra's monthly dividend from \$0.10 per share to \$0.01 per share starting with the December 2018 dividend. The Company's primary focus is to manage its bank debt during a period of volatile commodity prices. Bonterra 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, 2018	December 31, 2017
Working capital deficiency	30,281	27,790
Long-term bank debt	298,660	292,212
Net Debt	<b>328,941</b>	320,002

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

Net debt is a combination of long-term bank debt and working capital. Net debt for December 31, 2018 increased by \$8,939,000 from December 31, 2017 primarily due to low realized oil prices in the fourth quarter compared to the first nine months of 2018.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and adjustments of dividend payments. Included in the working capital deficiency as at December 31, 2018 is \$22,000,000 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 20 of the December 31, 2018 audited annual financial statements.

### Capital Expenditures

During the year ended December 31, 2018, the Company incurred capital expenditures of \$78,737,000 (December 31, 2017 - \$77,694,000). The costs primarily relate to \$65,030,000 for the drilling, completing, equipping and tying-in 34 gross (28.0 net) wells. An additional \$10,047,000 was spent on related infrastructure costs, recompletions and other capital expenditures. In addition, \$3,660,000 was incurred in 2018 related to E&E assets and incremental Cardium assets.

## Liability Management Ratio (“LMR”) Update

In 2018, 95 percent of the Company’s production was in the province of Alberta. The Company currently has an LMR rating of 2.06 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 on the Company’s bank facility as described in the notes to the Company’s audited annual financial statements. As of December 31, 2018, the Company has a bank facility with a limit of \$380,000,000 (December 31, 2017 - \$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, 2018 totaled \$298,660,000 (December 31, 2017 - \$292,212,000). The interest rates for the year ended December 31, 2018 on the Company’s Canadian prime rate loan and Banker’s Acceptances are between four to six percent. The loan is revolving to April 29, 2019 with a maturity date of April 30, 2020, subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limits of the credit facilities are reviewed semi-annually on or before April 30 and October 31 each year based mainly on the lender’s assessment of the Company’s reserves, future commodity prices and costs. On October 30, 2018, 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 13 of the December 31, 2018 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, 2018		December 31, 2017	
	Number	Amount (\$ 000s)	Number	Amount (\$ 000s)
Issued and fully paid - common shares				
Balance, beginning of year	<b>33,310,796</b>	<b>763,977</b>	33,302,435	763,788
Issued pursuant to the Company’s share option plan	<b>78,000</b>	<b>1,143</b>	8,361	143
Transfer from contributed surplus to share capital		<b>156</b>		46
Balance, end of period	<b>33,388,796</b>	<b>765,276</b>	33,310,796	763,977

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 3,338,880 (December 31, 2017 – 3,331,080) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option’s maximum term is five years. For additional information regarding options outstanding, see Note 17 of the December 31, 2018 audited annual financial statements.

## Commitments

The Company has entered into firm service gas transportation agreements in which the Company guarantees that certain minimum volumes of natural gas will be shipped on various gas transportation systems. The Company uses firm service delivery with Transcanada Pipeline on approximately 90 percent of its natural gas production. Considering substantially all 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 4.9 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, 2018 are as follows;

(\$ 000s)	2019	2020	2021	2022	2023	Thereafter	Total
Firm service commitments	958	945	909	843	812	487	4,954
Office lease commitments	522	516	516	519	503	-	2,576
<b>Total</b>	<b>1,480</b>	<b>1,461</b>	<b>1,425</b>	<b>1,362</b>	<b>1,315</b>	<b>487</b>	<b>7,530</b>

## Dividend Policy

For the year ended December 31, 2018, the Company declared and paid dividends of \$36,985,000 (\$1.11 per share) (December 31, 2017 – \$39,971,000) (\$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 shareholders with a combination of sustainable growth and meaningful dividend income. Bonterra's dividend payout ratio based on cash flow from operations was 32 percent for the year ended December 31, 2018 (38 percent for the year ended December 31, 2017).

Bonterra's capital spending and dividends to its shareholders are funded by cash flow from operating activities with the remaining free cash flow directed to debt repayment. To the extent that the excess cash flow from operations after dividends and capital spending is not sufficient, the shortfall may be funded by drawdowns on Bonterra's bank facility. Bonterra intends to provide dividends to shareholders that are sustainable by the Company with consideration to its liquidity and long-term operational strategy. The level of dividends is highly dependent upon cash flow generated from operations, which may fluctuate significantly due to changes in financial and operational performance, commodity prices, interest and exchange rates and many other factors. As such future dividends cannot be assured.

## Quarterly Financial Information

	2018			
For the periods ended	Q4	Q3	Q2	Q1
(\$ 000s except \$ per share)				
Revenue - oil and gas sales	34,988	63,817	67,458	57,124
Cash flow from operations	20,509	33,669	31,908	29,877
Net earnings (loss)	(10,909)	5,756	8,925	3,395
Per share - basic	(0.33)	0.17	0.27	0.10
Per share - diluted	(0.33)	0.17	0.27	0.10
	2017			
For the periods ended	Q4	Q3	Q2	Q1
(\$ 000s except \$ per share)				
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 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

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 fourth quarter of 2018, net earnings and cash flow were lower than 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.

## ***Drilling Locations***

This MD&A discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations, which are sometimes collectively referred to as "booked locations", are derived from the independent reserves evaluation prepared by Sproule Associates Ltd. as of December 31, 2018 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on Bonterra's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Of the 700 net drilling locations identified herein, 294 are proved locations, 4 are probable locations and 402 are unbooked locations. Unbooked locations have been identified by management as an estimation based on industry practice and internal review of our multi-year drilling activities, which include an

evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Bonterra will drill all unbooked drilling locations and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves or production. No locations have been assigned resources other than reserves (“ROTR”). All drilling counts cited herein are net.

### **Disclosure Controls and Procedures**

Disclosure controls and procedures (“DC&P”), as defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company’s annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief financial Officer of Bonterra evaluated the effectiveness of the design and operation of the Company’s DC&P. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Bonterra’s DC&P were effective at December 31, 2018.

### **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 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. 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 will adopt this standard using the modified retrospective approach on January 1, 2019. The Company has completed reviewing its various lease contracts. It has been concluded that the adoption of IFRS 16 will not have a material impact on Bonterra’s comprehensive income, cash flow and financial position. However, Bonterra will expand the disclosures in the notes to its financial statements as prescribed by IFRS 16.

Additional information relating to the Company may be found on [www.sedar.com](http://www.sedar.com) or visit our website at [www.bonterraenergy.com](http://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 12, 2019

*“Signed Robb D. Thompson”*

Robb D. Thompson  
Chief Financial Officer  
March 12, 2019

# INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Bonterra Energy Corp.

## Opinion

We have audited the financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statement of financial position as at December 31, 2018 and 2017, and the statement of comprehensive income, statement of changes in equity and statement of cash flow for the years then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2018 and 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

## Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

## Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the financial statements and our auditor's report thereon, in the Annual Report.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

## Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, 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.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

## **Auditor's Responsibilities for the Audit of the Financial Statements**

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit 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 Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this independent auditor's report is David Langlois.

"Signed Deloitte LLP"

Chartered Professional Accountants

Calgary, Alberta

March 12, 2019

## STATEMENT OF FINANCIAL POSITION

As at (\$ 000s)	Note	December 31, 2018	December 31, 2017
<b>Assets</b>			
<b>Current</b>			
Accounts receivable		7,797	20,536
Crude oil inventory		613	794
Prepaid expenses		3,183	2,535
Investments		116	274
		<b>11,709</b>	24,139
Investment in related party	6	258	476
Exploration and evaluation assets	7	4,422	4,217
Property, plant and equipment	8	985,773	995,075
Investment tax credit receivable	16	8,861	8,834
Goodwill	9	92,810	92,810
		<b>1,103,833</b>	1,125,551
<b>Liabilities</b>			
<b>Current</b>			
Accounts payable and accrued liabilities	10	18,743	26,130
Due to related party	11	12,000	12,000
Subordinated promissory note	12	10,000	12,500
Deferred consideration	14,21	1,247	1,299
		<b>41,990</b>	51,929
Bank debt	13	298,660	292,212
Deferred consideration	14,21	13,455	14,765
Decommissioning liabilities	15	132,134	126,631
Deferred tax liability	16	133,624	129,754
		<b>619,863</b>	615,291
<b>Subsequent events</b>	23		
<b>Shareholders' equity</b>			
Share capital	17	765,276	763,977
Contributed surplus		28,087	25,533
Accumulated other comprehensive loss		(664)	(339)
Retained earnings (deficit)		(308,729)	(278,911)
		<b>483,970</b>	510,260
		<b>1,103,833</b>	1,125,551

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

<b>For the year ended December 31</b>			
(\$ 000s, except \$ per share)	Note	2018	2017
<b>Revenue</b>			
Oil and gas sales, net of royalties	18	199,566	188,362
Other income	19	241	4,604
Deferred consideration	14	1,362	-
		<b>201,169</b>	<b>192,966</b>
<b>Expenses</b>			
Production		69,861	62,066
Office and administration		2,645	3,214
Employee compensation		4,633	4,535
Finance costs	5	18,534	19,719
Share-option compensation		2,710	4,511
Depletion and depreciation	8	91,453	89,339
Exploration and evaluation	7	291	1,566
		<b>190,127</b>	<b>184,950</b>
<b>Earnings before income taxes</b>		<b>11,042</b>	<b>8,016</b>
<b>Taxes</b>			
Current income tax expense (recovery)	16	(46)	(232)
Deferred income tax expense	16	3,921	5,742
		<b>3,875</b>	<b>5,510</b>
<b>Net earnings for the year</b>		<b>7,167</b>	<b>2,506</b>
<b>Other comprehensive income (loss)</b>			
Unrealized loss on investments		(376)	(871)
Deferred taxes on unrealized loss on investments		51	118
<b>Other comprehensive loss for the year</b>		<b>(325)</b>	<b>(753)</b>
<b>Total comprehensive income for the year</b>		<b>6,842</b>	<b>1,753</b>
<b>Net earnings per share - basic and diluted</b>	17	<b>0.22</b>	0.08
<b>Comprehensive income per share - basic and diluted</b>	17	<b>0.21</b>	0.05

See accompanying notes to these financial statements.

## STATEMENT OF CASH FLOW

For the years ended December 31

(\$ 000s)	Note	2018	2017
<b>Operating activities</b>			
Net earnings		7,167	2,506
Items not affecting cash			
Deferred income taxes		3,921	5,742
Deferred consideration		(1,362)	-
Share-option compensation		2,712	4,511
Depletion and depreciation		91,453	89,339
Exploration and evaluation expenditures		291	1,566
Gain on sale of property and equipment		-	(4,233)
Unwinding of the discount on decommissioning liabilities	15	3,069	3,013
Investment income		(65)	(49)
Interest expense		15,465	16,706
Change in non-cash working capital accounts:			
Accounts receivable		11,749	(283)
Crude oil inventory		49	53
Prepaid expenses		(648)	(6)
Investment tax credit receivable		(27)	-
Accounts payable and accrued liabilities		(1,000)	2,828
Decommissioning expenditures	15	(1,346)	(1,114)
Interest paid		(15,465)	(16,706)
<b>Cash provided by operating activities</b>		<b>115,963</b>	<b>103,873</b>
<b>Financing activities</b>			
Increase (decrease) of bank debt		6,448	(36,992)
Subordinated promissory note		(2,500)	-
Stock option proceeds		1,143	143
Dividends		(36,985)	(39,971)
<b>Cash used in financing activities</b>		<b>(31,894)</b>	<b>(76,820)</b>
<b>Investing activities</b>			
Investment income received		65	49
Exploration and evaluation expenditures	7	(535)	(738)
Property, plant and equipment expenditures	8	(78,202)	(76,956)
Proceeds on sale of property	21	-	52,005
Change in non-cash working capital accounts:			
Accounts payable and accrued liabilities		(6,387)	(1,934)
Accounts receivable		990	521
<b>Cash used in investing activities</b>		<b>(84,069)</b>	<b>(27,053)</b>
<b>Net change in cash in the year</b>		<b>-</b>	<b>-</b>
Cash, beginning of year		-	-
<b>Cash, end of year</b>		<b>-</b>	<b>-</b>

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 17)	Share Capital (Note 17)	Contributed surplus <sup>(1)</sup>	Accumulated other Comprehensive income (loss) <sup>(2)</sup>	Retained earnings (deficit)	Total shareholder's equity
<b>January 1, 2017</b>	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)
<b>December 31, 2017</b>	33,310,796	763,977	25,533	(339)	(278,911)	510,260
Share-option compensation			2,710			2,710
Exercise of options	78,000	1,143				1,143
Transfer to share capital on exercise of options		156	(156)			-
Comprehensive income (loss)				(325)	7,167	6,842
Dividends					(36,985)	(36,985)
<b>December 31, 2018</b>	33,388,796	765,276	28,087	(664)	(308,729)	483,970

<sup>(1)</sup> All amounts reported in Contributed Surplus relate to share-based payments.

<sup>(2)</sup> 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 the year ended December 31, 2018 and 2017.

### 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, 1015-4<sup>th</sup> 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 12, 2019.

#### b) Basis of Measurement

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

#### c) Functional and Presentation Currency

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

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

#### d) Significant Accounting Estimates and Judgments

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts. See Note 4 for more information.

#### e) Adopted Accounting Pronouncements

As of January 1, 2018, the Company adopted IFRS 15 “Revenue from contracts with customers”. IFRS 15 replaces the sections IAS 11 “Construction contracts”, IAS 18 “Revenue” and related interpretations. IFRS 15 provides a single, principled-based five-step model to be applied to all contracts with customers. 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. This standard also requires expanded disclosure requirements. The standard is required to be adopted either retrospectively or using a modified retrospective approach.

Bonterra used the modified retrospective approach to adopt the standard. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15. The Company has

reviewed its various revenue streams and underlying contracts with customers, and as result of this review, the adoptions of IFRS 15 did not have a material impact on the Company's statements of comprehensive income and financial position. However, the Company has expanded 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 Note 18. In addition, as a result of this adoption, the Company has revised the description of its accounting policy for revenue recognition.

#### **f) Future Accounting Pronouncements**

In January 2016, the IASB issued IFRS 16 "Leases", which replaces IAS 17 "Leases". IFRS 16 requires the recognition of lease assets and liabilities on the balance sheet 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. Certain short-term 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. 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.

IFRS 16 will be adopted by Bonterra on January 1, 2019. The Company is currently engaging and educating stakeholders and is reviewing corporate processes to ensure contract completeness when identifying leases. Identifying, gathering and analyzing contracts impacted by the adoption of the new standard is in progress. The Company anticipates that the adoption of IFRS 16 will not have a material impact on Bonterra's financial statements.

### **3. SIGNIFICANT ACCOUNTING POLICIES**

#### **a) Revenue Recognition**

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when or as Bonterra satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, and natural gas liquids usually coincides with title passing to the customer and the customer taking physical possession. The Company principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant. Collection of revenue associated with the sale of crude oil, natural gas and natural gas liquids occurs on or about the 25th of the month following production. 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 services 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.

### **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).

PP&E properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable developed reserve life, when commercial production in an area has commenced. 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.

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.

The Company performs an impairment test on all of its CGUs for any potential impairment or related recovery at least annually or when impairment or recovery indicators arise. For the year ended December 31, 2018 the Company also performed an impairment test due to a decrease in market capitalization for Bonterra and other Canadian Oil and Gas producers. 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, 2018.

## Bonterra 's Key Assumptions for Impairment

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029 <sup>(2)</sup>
WTI Crude oil \$US/Bbl <sup>(1)</sup>	63.00	67.00	70.00	71.40	72.83	74.28	75.77	77.29	78.83	80.41	82.02
AECO C-Spot \$Mmbtu <sup>(1)</sup>	1.95	2.44	3.00	3.21	3.30	3.39	3.49	3.58	3.68	3.78	3.88
Exchange rate US\$/Cdn	0.77	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

<sup>(1)</sup>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.

<sup>(2)</sup>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 five percent change in commodity prices or a one 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. FINANCE COSTS

A breakdown of finance costs for the years ended:

(\$ 000s)	<b>December 31, 2018</b>	December 31, 2017
Interest expense on bank debt	14,561	15,807
Interest expense on amounts owing to related party	362	274
Interest expense on subordinated promissory note and other	542	625
Unwinding of the fair value of decommissioning liabilities	3,069	3,013
	<b>18,534</b>	<b>19,719</b>

## 6. INVESTMENT IN RELATED PARTY

The investment consists of 1,034,523 (December 31, 2017 – 1,034,523) common shares in Pine Cliff Energy Ltd. (“Pine Cliff”), a company with some common directors 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.

## 7. EXPLORATION AND EVALUATION ASSETS

(\$ 000s)	
<b>Cost and carrying amount</b>	
Balance at January 1, 2017	7,073
Additions	738
Transfers to property, plant and equipment	(2,028)
Expiry of exploration and evaluation assets	(1,566)
<b>Balance at December 31, 2017</b>	<b>4,217</b>
Additions	535
Transfers to property, plant and equipment	(39)
Expiry of exploration and evaluation assets	(291)
<b>Balance at December 31, 2018</b>	<b>4,422</b>

## 8. PROPERTY, PLANT AND EQUIPMENT

Cost (\$ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at January 1, 2017	1,280,953	315,039	2,082	1,598,074
Additions <sup>(1)</sup>	60,331	21,273	99	81,703
Transfers from exploration and evaluation assets	2,028	-	-	2,028
Adjustment to decommissioning liabilities <sup>(2)</sup>	23,791	-	-	23,791
Disposal and other	(49,040)	(11,583)	-	(60,623)
<b>Balance at December 31, 2017</b>	<b>1,318,063</b>	<b>324,729</b>	<b>2,181</b>	<b>1,644,973</b>
Additions	60,779	17,319	104	78,202
Transfers from exploration and evaluation assets	39	-	-	39
Adjustment to decommissioning liabilities <sup>(2)</sup>	3,780	-	-	3,780
<b>Balance at December 31, 2018</b>	<b>1,382,661</b>	<b>342,048</b>	<b>2,285</b>	<b>1,726,994</b>

  

Accumulated depletion and depreciation (\$ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at January 1, 2017	(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
<b>Balance at December 31, 2017</b>	<b>(529,434)</b>	<b>(118,757)</b>	<b>(1,707)</b>	<b>(649,898)</b>
Depletion and depreciation	(75,198)	(16,170)	(85)	(91,453)
Other	130	-	-	130
<b>Balance at December 31, 2018</b>	<b>(604,502)</b>	<b>(134,927)</b>	<b>(1,792)</b>	<b>(741,221)</b>

### Carrying amounts as at:

(\$ 000s)

December 31, 2017	788,629	205,972	474	995,075
<b>December 31, 2018</b>	<b>778,159</b>	<b>207,121</b>	<b>493</b>	<b>985,773</b>

<sup>(1)</sup> Included in additions is \$4,747,000 of property, plant and equipment received from the GORR sale as disclosed in Note 21.

<sup>(2)</sup> Adjustment to decommissioning liabilities is due to a decrease in the risk-free rate and a change in estimate on decommissioning costs.

There were no impairment losses or reversals recorded in the statement of comprehensive income (loss) for the year ended December 31, 2018 and 2017.

## 9. 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, 2018 and 2017.

## 10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(\$ 000s)	December 31, 2018	December 31, 2017
Accounts payable	14,489	19,547
Accrued liabilities	4,254	6,583
	<b>18,743</b>	26,130

## 11. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2018, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company \$12,000,000 (December 31, 2017 - \$12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8<sup>th</sup> 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 2018 was \$362,000 (December 31, 2017 - \$274,000).

The Company provides executive and marketing services for Pine Cliff Energy Ltd. (Pine Cliff). All services that were performed were charged at estimated fair value. As at December 31, 2018, the Company had an account receivable from Pine Cliff of \$71,000 (December 31, 2017 - \$36,000).

### Compensation for Key Management Personnel

(\$ 000s)	December 31, 2018	December 31, 2017
Compensation	1,526	1,424
Share-based payments	1,178	1,739
Total compensation	2,704	3,163

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

## 12. SUBORDINATED PROMISSORY NOTE

As at December 31, 2018, Bonterra had \$10,000,000 (December 31, 2017 - \$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 \$514,000 (December 31, 2017 - \$625,000). On January 2, 2019 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.

## 13. BANK DEBT

As at December 31, 2018, the Company has a bank facility of \$380,000,000 (December 31, 2017 - \$380,000,000). Comprised of a \$330,000,000 syndicated revolving credit facility and a \$50,000,000 non-syndicated revolving credit facility. The amount drawn under the bank facility at December 31, 2018 was \$298,660,000 (December 31, 2017 - \$292,212,000). The amounts borrowed under the bank facility bears interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 0.50 percent and 3.50 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 29, 2019, with a maturity date of April 30, 2020, 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 and based on the lender's assessment of the Company's reserves, future commodity prices and costs. On October 30, 2018, the Company successfully renewed its available lending limit at \$380,000,000 with no changes to the current terms and conditions.

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, 2018 (December 31, 2017 - \$900,000). Security for the bank facility consists of various floating demand debentures totaling \$750,000,000 (December 31, 2017 - \$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, 2018 consolidated debt is \$320,660,000.
- 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, 2018, the Company is in compliance with all covenants.

#### 14. 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, 2018	December 31, 2017
<b>Deferred consideration, January 1</b>	<b>16,064</b>	-
Sale of a royalty interest on Pembina Cardium properties (Note 21)	-	16,064
Recognition of deferred consideration	<b>(1,362)</b>	-
Deferred consideration, end of year	<b>14,702</b>	16,064
Less current portion of deferred consideration	<b>(1,247)</b>	(1,299)
<b>Non-current portion of deferred consideration</b>	<b>13,455</b>	14,765

#### 15. DECOMMISSIONING LIABILITIES

At December 31, 2018, the estimated total undiscounted amount required to settle the decommissioning liabilities was \$333,384,000 (December 31, 2017- \$298,111,000). The provision has been calculated assuming a 2.0 percent inflation rate (December 31, 2017 – 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 2.32 percent (December 31, 2017 – 2.42 percent).

(\$ 000s)	December 31, 2018	December 31, 2017
<b>Decommissioning liabilities, January 1</b>	<b>126,631</b>	100,941
Adjustment to decommissioning liabilities <sup>(1)</sup>	<b>3,780</b>	23,791
Liabilities settled during the period	<b>(1,346)</b>	(1,114)
Unwinding of the discount on decommissioning liabilities	<b>3,069</b>	3,013
<b>Decommissioning liabilities, end of year</b>	<b>132,134</b>	126,631

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

## 16. INCOME TAXES

(\$ 000s)	December 31, 2018	December 31, 2017
Deferred tax asset (liability) related to:		
Investments	82	32
Exploration and evaluation assets and property, plant and equipment	(172,449)	(169,770)
Investment tax credits	(2,392)	(2,385)
Decommissioning liabilities	35,676	34,190
Corporate tax losses carried forward	7,354	10,051
Share issue costs	6	29
Corporate capital tax losses carried forward	8,777	8,699
Unrecorded benefits of capital tax losses carried forward	(8,777)	(8,699)
Unrecorded benefits of successored resource related pools	(1,901)	(1,901)
<b>Deferred tax asset (liability)</b>	<b>(133,624)</b>	<b>(129,754)</b>

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

(\$ 000s)	December 31, 2018	December 31, 2017
Earnings (loss) before taxes	11,042	8,016
Combined federal and provincial income tax rates	27.00%	27.00%
Income tax provision calculated using statutory tax rates	2,981	2,164
Increase (decrease) in taxes resulting from:		
Share-option compensation	732	1,218
Change in unrecorded benefits of tax pools	78	1,988
Change in estimates and other	84	140
	<b>3,875</b>	<b>5,510</b>

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	84,491
Share issue costs	20	21
Canadian oil and gas property expenditures	10	93,773
Canadian development expenditures	30	148,573
Canadian exploration expenditures	100	8,063
Federal income tax losses carried forward <sup>(1)</sup>	100	44,315
Provincial income tax losses carried forward <sup>(2)</sup>	100	5,898
		<b>385,134</b>

<sup>(1)</sup> Federal income tax losses carried forward expire in the following years; 2035 - \$8,253,000; 2036 - \$35,853,000; 2037 - \$209,000

<sup>(2)</sup> Provincial income tax losses carried forward expire in 2036 - \$ 5,689,000; 2037 - \$209,000

The Company has \$8,861,000 (December 31, 2017 - \$8,834,000) of investment tax credits that expire in the following years; 2021 - \$1,851,000; 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 \$65,015,000 (December 31, 2017 - \$64,435,000) of capital losses carried forward which can only be claimed against taxable capital gains.

## 17. SHAREHOLDERS' EQUITY

Authorized

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

	December 31, 2018		December 31, 2017	
	Number	Amount (\$ 000s)	Number	Amount (\$ 000s)
Issued and fully paid - common shares				
Balance, beginning of year	33,310,796	763,977	33,302,435	763,788
Issued pursuant to the Company's share option plan	78,000	1,143	8,361	143
Transfer from contributed surplus to share capital		156		46
Balance, end of year	33,388,796	765,276	33,310,796	763,977

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, 2018	December 31, 2017
Basic shares outstanding	33,327,777	33,309,578
Dilutive effect of share options <sup>(1)</sup>	493	2,149
Diluted shares outstanding	33,328,270	33,311,727

<sup>(1)</sup> The Company did not include 2,775,000 share-options (December 31, 2017 – 2,778,000) in the dilutive effect of share-options calculations as these share-options were anti-dilutive.

For the year ended December 31, 2018 Company declared and paid dividends of \$36,985,000 (\$1.11 per share) (December 31, 2017 - \$39,971,000 (\$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 3,338,880 (December 31, 2017 – 3,331,080 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 options as of December 31, 2018 and changes during the year ended are presented below:

	Number of options	Weighted average exercise price
At January 1, 2017	2,737,000	\$30.50
Options granted	1,936,000	14.91
Options exercised	(14,000)	20.46
Options forfeited	(256,000)	23.03
Options expired	(1,597,000)	32.25
At December 31, 2018	2,806,000	\$19.48
Options granted	1,073,000	6.39
Options exercised	(78,000)	14.67
Options forfeited	(53,000)	19.01
Options expired	(954,000)	28.23
At December 31, 2018	2,794,000	\$11.62

The following table summarizes information about options outstanding and exercisable as at December 31, 2018:

Range of exercise prices	Options outstanding			Options exercisable		
	Number outstanding	Weighted-average remaining contractual life	Weighted- average exercise price	Number exercisable	Weighted- average exercise price	
\$ 5.00 - \$ 10.00	1,031,000	2.1 years	\$ 5.93	-	\$ -	
10.01 - 20.00	1,731,000	1.3 years	14.74	30,000	14.56	
20.01 - 35.00	32,000	0.9 years	25.93	16,000	27.95	
\$ 5.00 - \$ 35.00	2,794,000	1.6 years	\$ 11.62	46,000	\$ 14.83	

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 2018, the Company granted 1,073,000 options with an estimated fair value of \$1,227,000 or \$1.19 per option using the Black-Scholes option pricing model with the following key assumptions:

	December 31, 2018	December 31, 2017
Weighted-average risk free interest rate (%) <sup>(1)</sup>	1.93	1.48
Weighted-average expected life (years)	1.2	1.5
Weighted-average volatility (%) <sup>(2)</sup>	46.45	47.23
Forfeiture rate (%)	7.55	7.68
Weighted average dividend yield (%)	2.22	8.18

<sup>(1)</sup> 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.

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

## 18. OIL AND GAS SALES, NET OF ROYALTIES

(\$ 000s)	December 31, 2018	December 31, 2017
Oil and gas sales		
Crude oil	194,137	171,415
Natural gas liquids	14,645	10,242
Natural gas	14,606	20,909
	<b>223,388</b>	202,566
Less royalties:		
Crown	(15,157)	(10,178)
Freehold, gross overriding royalties and other	(8,665)	(4,026)
	<b>(23,822)</b>	(14,204)
Oil and gas sales, net of royalties	<b>199,566</b>	188,362

## 19. OTHER INCOME

(\$ 000s)	December 31, 2018	December 31, 2017
Investment income	65	74
Administrative income	176	297
Gain on sale of property and equipment	-	4,233
Deferred consideration	1,362	-
Other income	1,603	4,604

## 20. FINANCIAL 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 2.8:1 compared to 3.1:1 in 2017. The decrease in net debt to cash flow ratio is primarily due to \$52,000,000 received on December 20, 2017 for the sale of a royalty interest in the Pembina Cardium properties (see disposition Note 21) and improved commodity prices realized in 2018. However, in the fourth quarter of 2018, Canadian oil experienced large differentials compared to world prices due to a lack of takeaway capacity. To manage its bank debt during a period of low commodity prices the Company reduced planned capital expenditures for the 2017 and 2018 fiscal years. Additionally, in December of 2018, the Company reduced the monthly dividend from \$0.10 to \$0.01 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, 2018 are as follows:

(\$ 000s)	
Bank debt	298,660
Accounts payable and accrued liabilities	18,743
Due to related party	12,000
Subordinated promissory note	10,000
Current assets	(11,709)
<b>Net debt</b>	<b>327,694</b>
Cash flow from operations	115,963
<b>Net debt ratio</b>	<b>2.8</b>

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.

At December 31, 2018, the Company had the following physical natural gas sales contract in place:

Product	Type of contract	Volume	Term	Contract price
Oil	Costless physical oil collar - WTI	500 BBL/day	November 1 to December 31, 2018	Floor price \$70.00 US/BBL Ceiling price \$79.50 US/BBL

<sup>(1)</sup> WTI refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States

<sup>(2)</sup> Basis differential is the difference between WTI and MSW stream index

### 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 \$10,000,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, are at bank prime plus or minus various percentages as well as by means of banker's acceptances (BAs) within the Company's credit facility. The subordinated promissory note is at a fixed interest rate of 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 \$2,268,000.

### Equity price risk

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

### Foreign exchange risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. 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 \$7,797,000 accounts receivable balance at December 31, 2018 (December 31, 2017 - \$20,536,000) over 74 percent (2017 – 84 percent) relates to product sales with national and international oil and gas companies.

On a quarterly basis, the Company assesses if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2018, 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, 2018, approximately \$397,000 or 5 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2017 - \$1,434,000 or 7 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, 2018 is \$1,402,000 (December 31, 2017 - \$1,146,000) 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	18,743	-
Due to related parties	Yes - Liability	12,000	-
Subordinated promissory note	Yes - Liability	10,000	-
Bank Debt	Yes - Liability	-	298,660
Firm service commitments	No	958	3,996
Office lease commitments	No	522	2,054
<b>Total</b>		<b>42,223</b>	<b>304,710</b>

## 21. 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.

## 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 4.9 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, 2018 are as follows:

(\$ 000s)	2019	2020	2021	2022	2023	Thereafter	Total
Firm service commitments	958	945	909	843	812	487	4,954
Office lease commitments	522	516	516	519	503	-	2,576
<b>Total</b>	<b>1,480</b>	<b>1,461</b>	<b>1,425</b>	<b>1,362</b>	<b>1,315</b>	<b>487</b>	<b>7,530</b>

## 23. SUBSEQUENT EVENTS

### Dividends

Subsequent to December 31, 2018, the Company declared the following dividends:

Date declared	Record date	\$ per share	Date payable
January 2, 2019	January 15, 2019	0.01	January 31, 2019
February 1, 2019	February 15, 2019	0.01	February 28, 2019
March 1, 2019	March 15, 2019	0.01	March 29, 2019

## Corporate Information

### Board of Directors

G. F. Fink - Chairman  
G. J. Drummond  
R. M. Jarock  
D. Reuter  
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  
ATB Financial  
Business Development Bank of Canada

### Head Office

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