Management's Discussion and Analysis

The following report dated November 6, 2019 is a review of the operations and current financial position for the three and nine months ended September 30, 2019 for Bonterra Energy Corp. ("Bonterra" or "the Company") and should be read in conjunction with the unaudited condensed financial statements and the audited financial statements including the notes related thereto for the fiscal year ended December 31, 2018 presented under International Financial Reporting Standards (IFRS).

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 International Financial Reporting Standards ("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.

QUARTERLY COMPARISONS

	2019			2018			
As at and for the periods ended ($ 000s except $ per share)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1
Financial							
Revenue - oil and gas sales	**47,320**	54,852	49,834	34,988	63,817	67,458	57,124
Cash flow from operations	**19,774**	25,468	15,123	20,509	33,669	31,908	29,877
Per share - basic and diluted	**0.59**	0.76	0.45	0.61	1.01	0.96	0.90
Dividend payout ratio	**5%**	4%	7%	34%	30%	31%	33%
Cash dividends per share	**0.03**	0.03	0.03	0.21	0.30	0.30	0.30
Net earnings (loss)	**(1,276)**	23,131	1,457	(10,909)	5,756	8,925	3,395
Per share - basic and diluted	**(0.04)**	0.69	0.04	(0.33)	0.17	0.27	0.10
Capital expenditures	**17,845**	9,042	21,062	4,785	18,814	18,970	36,168
Total assets	**1,133,137**	1,123,513	1,124,043	1,103,833	1,137,748	1,147,501	1,142,670
Working capital deficiency	**24,599**	22,238	30,139	30,281	35,319	27,069	46,630
Long-term debt	**283,470**	288,545	296,594	298,660	293,197	303,413	291,994
Shareholders' equity	**506,011**	507,659	484,980	483,970	500,507	503,979	504,240
Operations							
Oil (barrels per day)	**7,157**	7,746	7,081	7,756	7,949	8,743	8,034
NGLs (barrels per day)	**1,009**	970	949	1,025	1,070	984	900
Natural gas (MCF per day)	**23,820**	23,750	23,938	24,045	24,144	25,317	24,701
Total BOE per day	**12,136**	12,674	12,020	12,789	13,043	13,946	13,051

	2017			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	54,192	46,349	52,695	49,330
Cash flow from operations	26,472	25,491	27,370	24,540
Per share - basic and diluted	0.79	0.77	0.82	0.74
Dividend 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 [1]	-	-	-
Total assets	1,125,551	1,146,498	1,173,936	1,156,398
Working capital deficiency	27,790	28,260	29,759	39,483
Long-term debt	292,212	345,322	341,070	330,118
Shareholders' equity	510,260	517,719	529,844	535,742
Operations				
Oil (barrels per day)	7,766	8,038	8,287	7,533
NGLs (barrels per day)	963	1,000	843	813
Natural gas (MCF per day)	24,466	25,460	24,138	22,243
Total BOE per day	12,807	13,281	13,153	12,053

[1] 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, as well as production volumes and foreign exchange rates. The following table depicts selective market benchmark commodity prices, differentials and foreign exchange rates in the last eight quarters to assist in understanding how past volatility has impacted Bonterra's financial and operating performance. The increases or decreases for Bonterra's realized average price for oil and natural gas for each of the eight quarters is also outlined in detail in the following table.

	Q3-2019	Q2-2019	Q1-2019	Q4-2018	Q3-2018	Q2-2018	Q1-2018	Q4-2017
Crude oil								
WTI (U.S.$/bbl)	**56.45**	59.81	54.90	58.81	69.50	67.88	62.87	55.40
WTI to MSW Stream Index								
Differential (U.S.$/bbl)(1)	**(4.66)**	(4.62)	(4.85)	(26.30)	(6.83)	(5.45)	(5.89)	(1.14)
Foreign exchange								
U.S.$ to Cdn$	**1.3207**	1.3375	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717
Bonterra average realized								
oil price (Cdn$/bbl)	**65.49**	71.27	64.87	38.96	77.20	76.51	67.78	65.16
Natural gas								
AECO (Cdn$/mcf)	**0.91**	1.03	2.61	1.55	1.19	1.18	2.07	1.68
Bonterra average realized								
gas price (Cdn$/mcf)	**0.96**	1.09	2.70	1.77	1.37	1.16	2.24	1.90

(1) 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 (particularly North American) 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;
- Crude oil curtailments;
- Weather; and
- Timing and duration of plant, refinery and pipeline maintenance.

Volatility in WTI benchmark pricing has continued through the third quarter of 2019. Uncertainties around both global supply and demand have contributed to the crude oil price volatility, as well as heightened geopolitical concerns stemming from an attack on Saudi Arabia's largest crude processing facility. Concern about weak demand in the 2nd half of 2019 and continuing into 2020, comes from a variety of factors, including but not limited to global trade issues between the US and China. With respect to supply, there is uncertainty whether crude oil supply growth, such as the shale oil growth in the US, will outpace cuts that were extended by OPEC and several non-OPEC nations in the first half of 2019. In Canada, volatility has subsided somewhat as crude curtailments mandated by the Alberta Government, along with incremental rail and seasonal factors have resulted in a significant decrease in crude inventories and a narrowing of the differential for all grades of Canadian crude.

While the crude curtailment program has reduced Canadian crude price volatility, it has not negated the need for incremental pipeline capacity out of the country. Looking forward, completion of any proposed pipeline expansion projects or increasing Canada's export capabilities by expanding capacity on existing lines will have a positive effect on the movement and pricing of Canadian barrels. In addition to pipelines, industry can utilize rail to ship crude. Incremental shipments by rail are expected to continue throughout 2019 and into 2020. 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 the lack of pipeline capacity.

The AECO benchmark price for natural gas continued to exhibit significant weakness through the third quarter of 2019 due to much lower seasonal demand and insufficient egress, either out of the basin or into storage, for the current level of supply. Pricing instability should ease moving into the 4th quarter of 2019, as weather-related demand begins to increase. Planned facility additions for the NGTL gas transmission system and a positive final investment decision by LNG Canada may improve sentiment towards western Canadian-based natural gas producers. While these projects do not impact near-term supply/demand imbalances, they do 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 2019 (1)

Impact on cash flow	Change ($)	$000s	$ per share (2)
Realized crude oil price ($/bbl)	1.00	2,830	0.08
Realized natural gas price ($/mcf)	0.10	1,019	0.03
U.S.$ to Canadian $ exchange rate	0.01	1,500	0.04

(1) This analysis uses current royalty rates, annualized estimated average production of 12,600 BOE per day and no changes in working capital

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

Business Overview, Strategy and Key Performance Drivers

Bonterra continues to remain focused on long-term sustainability and improving its balance sheet through debt reduction. In the first nine months of 2019, the Company decreased net debt by $20,872,000, or six percent, over net debt levels as at December 31, 2018. With a responsible capital allocation plan for 2019, Bonterra intends to continue managing production and debt levels to ensure the Company is well positioned for 2020.

To date in 2019, Bonterra has continued to develop its high quality, oil-weighted assets in the Pembina and Willesden Green Cardium pool of Alberta. For the first nine months of 2019, Bonterra invested approximately $47,949,000 (representing 85 percent of the lower end of its $57,000,000 to $77,000,000 annual capital budget), of which $41,470,000 was directed to drill and complete 26 gross (20.6 net) horizontal wells and tie-in 24 gross (18.6 net) wells. The remaining two wells were tied-in and placed on production early in October 2019. An additional $6,479,000 was spent on related infrastructure costs, recompletions and other capital expenditures. The Company anticipates full year capital spending will be at the lower end of its 2019 annual capital guidance, which will include drilling 3 gross (3.0 net) wells in Q4 2019 that will be completed in Q1 2020.

Production averaged 12,136 BOE per day during Q3 2019. Approximately 526 BOE per day was off-line through the period due to facility turnarounds and preserving value by shutting-in low commodity price gas wells in British Columbia. The Company is currently producing approximately 12,750 BOE per day, or 5 percent higher than the Q3 2019 average, and expects average annual production to be approximately two percent lower than the 2019 guidance of 12,600 BOE per day to 13,200 BOE per day.

In response to mandatory production curtailments instituted by the Alberta Government in January 2019, differentials on Canadian sweet crude oil have narrowed significantly, and as a result, the Company benefitted from a stronger commodity price environment during the nine months ended September 30, 2019. As part of Bonterra's ongoing efforts to diversify crude oil pricing and to protect future cash flow, the Company entered into physical delivery sales and risk management contracts for the fourth quarter of 2019. During Q4 2019, the Company will receive fixed Edmonton Par prices on 2,500 bbls per day of crude oil in the month of October and 3,500 bbls per day of crude oil in the months of November and December. The fixed Edmonton Par prices range between $62.90 CAD per bbl to $68.69 CAD per bbl. The Company also diversified its natural gas pricing for the warmer months of 2020 by entering into a physical delivery sales contracts for 5,000 GJs per day from April 1, 2020 to October 31, 2020 ranging between $1.55 CAD per GJ to $1.64 CAD per GJ.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending, the payment of 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						Nine months ended			
	September 30, 2019		June 30, 2019		September 30, 2018		**September 30, 2019**		September 30, 2018	
	Gross[1]	**Net[2]**	Gross[1]	Net[2]	Gross[1]	Net[2]	**Gross[1]**	**Net[2]**	Gross[1]	Net[2]
Crude oil horizontal-operated	**7**	**7.0**	2	2.0	7	6.9	**20**	**20.0**	27	26.8
Crude oil horizontal-non-operated	**5**	**0.5**	-	-	3	0.6	**6**	**0.6**	5	0.8
Total	**12**	**7.5**	2	2.0	10	7.5	**26**	**20.6**	32	27.6
Success rate		**100%**		100%		100%		**100%**		100%

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

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

During the first nine months of 2019, the Company drilled 20 gross (20.0 net) wells and completed 20 gross (20.0 net) wells, of which 18 gross (18.0 net) wells were tied-in and placed on production. The remaining two gross (2.0 net) wells commenced production in October 2019. The Company plans to drill 3 gross (3.0 net) wells in December that will be completed in Q1 2020.

In addition, six gross (0.6 net) non-operated wells were drilled, completed, equipped and placed on production during the first nine months of 2019.

Production

	Three months ended			Nine months ended	
	September 30, 2019	June 30, 2019	September 30, 2018	**September 30, 2019**	September 30, 2018
Crude oil (barrels per day)	**7,157**	7,746	7,949	**7,328**	8,242
NGLs (barrels per day)	**1,009**	970	1,070	**976**	985
Natural gas (MCF per day)	**23,820**	23,750	24,144	**23,836**	24,719
Average BOE per day	**12,136**	12,674	13,043	**12,277**	13,347

The Company averaged 12,277 BOE per day for the first nine months of 2019, compared to 13,347 BOE per day for the same period in 2018, reflecting significantly reduced capital in 2019 compared to the comparable period in 2018, which led to fewer new wells coming on production. In addition, for the first nine months of 2019, an average of approximately 440 BOE per day of production was shut-in primarily due to facility turnarounds being undertaken on a large number of gas plants and batteries, as well as the voluntary shut-in of British Columbia natural gas wells due to low realized natural gas prices.

Third quarter 2019 production was lower than the previous quarter due to the timing of new wells being brought onto production, coupled with 580 BOE per day of production that was shut-in due to the reasons outlined above.

Cash Netback

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

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
$ per BOE	**2019**	2019	2018	**2019**	2018
Production volumes (BOE)	**1,116,506**	1,153,375	1,199,929	**3,351,689**	3,643,642
Gross production revenue	**42.38**	47.56	53.18	**45.35**	51.71
Royalties	**(3.76)**	(3.05)	(6.17)	**(3.50)**	(5.51)
Production costs	**(14.32)**	(15.88)	(16.31)	**(15.03)**	(14.58)
Field netback	**24.30**	28.63	30.70	**26.82**	31.62
General and administrative	**(1.05)**	(1.95)	(1.45)	**(1.48)**	(1.61)
Interest and other	**(3.35)**	(3.52)	(2.94)	**(3.48)**	(3.18)
Cash netback	**19.90**	23.16	26.31	**21.86**	26.83

Cash netbacks decreased in the first nine months of 2019 compared to 2018 primarily due to lower realized commodity prices and increased production costs per BOE, which were partially offset by a decrease in royalties per BOE.

Relative to Q2 2019, cash netbacks for Q3 2019 decreased due to lower realized commodity prices and a gas cost allowance recovery on natural gas crown royalties in the second quarter of 2019, which were partially offset by lower production costs per BOE.

Oil and Gas Sales

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
	2019	2019	2018	**2019**	2018
Revenue - oil and gas sales ($ 000s)					
Crude oil	**43,121**	50,235	56,457	**134,699**	166,336
NGL	**2,085**	2,253	4,325	**7,020**	11,372
Natural gas	**2,114**	2,364	3,035	**10,287**	10,692
	47,320	54,852	63,817	**152,006**	188,400
Average realized prices:					
Crude oil ($ per barrel)	**65.49**	71.27	77.20	**67.33**	73.93
NGLs ($ per barrel)	**22.45**	25.53	43.95	**26.34**	42.28
Natural gas ($ per MCF)	**0.96**	1.09	1.37	**1.58**	1.58
Average ($ per BOE)	**42.38**	47.56	53.18	**45.35**	51.71
Average BOE per day	**12,136**	12,674	13,043	**12,277**	13,347

Revenue from oil and gas sales in the first nine months of 2019 decreased by $36,394,000, or 19 percent, compared to the same period in 2018. The decrease in oil and gas sales was primarily driven by an eight percent decrease in production volumes and a decrease in commodity prices for oil and NGLs. The quarter-over-quarter decrease in oil and gas sales was primarily due to a decrease in crude oil prices and lower production volumes compared to Q2 2019.

The Company's product split on a revenue basis for 2019 is weighted approximately 93 percent to crude oil and NGLs.

Royalties

($ 000s)	Three months ended September 30, 2019	June 30, 2019	September 30, 2018	Nine months ended September 30, 2019	September 30, 2018
Crown royalties	**2,563**	1,683	4,784	**6,450**	12,681
Freehold, gross overriding and other royalties	**1,632**	1,832	2,616	**5,274**	7,411
Total royalties	**4,195**	3,515	7,400	**11,724**	20,092
Crown royalties - percentage of revenue	**5.4**	3.1	7.5	**4.2**	6.7
Freehold, gross overriding and other royalties - percentage of revenue	**3.4**	3.3	4.1	**3.5**	3.9
Royalties - percentage of revenue	**8.8**	6.4	11.6	**7.7**	10.6
Royalties $ per BOE	**3.76**	3.05	6.17	**3.50**	5.51

Royalties paid by the Company consist of both crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and other royalties. Total royalties decreased by $2.01 per BOE for the first nine months of 2019 compared to the same period in 2018. The decrease in royalties is primarily a result of lower commodity prices in 2019 than the prior year. The quarter-over-quarter increase in royalties of $0.71 per BOE was primarily due to an annual gas cost allowance credit received in Q2 2019 offset by reduced royalties on gas and NGLs from lower commodity prices in Q3 2019 compared to Q2 2019.

Production Costs

($ 000s except $ per BOE)	Three months ended September 30, 2019	June 30, 2019	September 30, 2018	Nine months ended September 30, 2019	September 30, 2018
Production costs	**15,989**	18,312	19,572	**50,369**	53,115
$ per BOE	**14.32**	15.88	16.31	**15.03**	14.58

Production costs for the first nine months of 2019 decreased by $2,746,000 compared to 2018 primarily due to decreased production, which was partially offset by higher trucking and power costs. The increased trucking and power costs combined with shut-in production caused operating costs on a BOE basis to increase by $0.45 per BOE.

Production costs for Q3 2019 decreased by $2,323,000 compared to Q2 2019 primarily due to less oil and water trucking from new well production, decreased power and maintenance costs.

Other Income

($ 000s)	Three months ended September 30, 2019	June 30, 2019	September 30, 2018	Nine months ended September 30, 2019	September 30, 2018
Investment income	**11**	21	21	**43**	48
Administrative income	**25**	30	39	**80**	133
Deferred consideration	**301**	304	332	**927**	1,060
Gain on sale of property	**3**	-	-	**5**	-
Unrealized loss on risk management contracts	**(58)**	-	-	**(58)**	-
	282	355	392	**997**	1,241

Deferred consideration relates to a deferred gain on the sale of a two percent overriding royalty interest, which is recognized into revenue using the same unit-of-production method as the encumbered property, plant and equipment assets.

The market value and carrying value of the investments held by the Company at September 30, 2019 was $265,000 (September 30, 2018 - $530,000). There were no dispositions during the nine months ended September 30, 2019 or

2018. 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.

During the third quarter, Bonterra entered into financial derivatives to minimize commodity price risk on crude oil sales. The financial derivatives outstanding are for the period from October 1, 2019 to December 31, 2019 on a total of 153,000 barrels of crude oil (approximately 1,000 barrels of oil per day for the month of October and 2,000 barrels of oil per day for the months of November and December) at fixed Edmonton Par prices ranging from $62.90 to $65.00 CAD per barrel. These contracts are not considered normal sales contracts and are recorded at fair value.

General and Administration (G&A) Expense

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per BOE)	**2019**	2019	2018	**2019**	2018
Employee compensation expense	**987**	1,119	1,202	**3,202**	3,937
Office and administrative expense	**185**	1,131	534	**1,754**	1,946
Total G&A expense	**1,172**	2,250	1,736	**4,956**	5,883
$ per BOE	**1.05**	1.95	1.45	**1.48**	1.61

The decrease of $735,000 in employee compensation expense for the first nine months of 2019 compared to 2018 is primarily due to a lower bonus accrual from decreased earnings before income taxes. The Company has a bonus plan in which the bonus pool consists of a range between 2.5 percent to 3.5 percent of earnings before income taxes.

Office and administrative expenses for the first nine months of 2019 decreased by $192,000 compared to 2018 primarily due to a decrease in bank charges and the allowance for doubtful accounts expense. The decrease was partially offset by an increase in software and consulting services. The decrease in Q3 2019 over Q2 2019 was primarily due to decreased software costs, a reduction in the allowance for doubtful accounts expense and the bank renewal fees incurred in the second quarter.

Finance Costs

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per BOE)	**2019**	2019	2018	**2019**	2018
Interest on long-term debt	**3,586**	3,919	3,352	**11,203**	11,116
Other interest	**194**	192	230	**579**	666
Interest expense	**3,780**	4,111	3,582	**11,782**	11,782
$ per BOE	**3.39**	3.56	2.99	**3.52**	3.23
Unwinding of the discounted value of decommissioning liabilities	**731**	747	789	**2,221**	2,307
Total finance costs	**4,511**	4,858	4,371	**14,003**	14,089

Interest on long-term debt increased in the first nine months of 2019 compared to the first nine months of 2018 due to increased interest rates as a result of a higher net debt to EBITDA ratio for Q4 2018 which was in effect during Q2 2019. Interest costs for the first nine months of 2019 was partially offset by lower average long-term debt outstanding of approximately $3,387,000. Quarter-over-quarter interest on long-term debt decreased as a result of a lower net debt to EBITDA ratio in effect for the current quarter and reduced average long-term debt of $6,562,000. The Company anticipates interest rates on long-term debt will decrease in Q4 2019 from an improved net debt to EBITDA ratio due to higher realized oil pricing compared to Q4 2018 and the Company's continued focus on debt repayment. 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 $7,500,000 subordinated promissory note from a private investor. For more information about the subordinated promissory note, refer to Note 5 of the September 30, 2019 condensed financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,172,000.

Share-Option Compensation

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Share-option compensation	**649**	620	753	**1,828**	2,261

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 directors, officers and employees.

Share-option compensation decreased by $433,000 in the first nine months of 2019 compared to the same period a year ago. This decline is due to most of the options issued in 2017 (which were fully amortized in 2018) having higher share price volatility than the options issued in the fourth quarter of 2018 (which will be fully amortized in 2019).

Based on the outstanding options as of September 30, 2019, the Company has an unamortized expense of $459,000, of which $287,000 will be recorded for the remainder of 2019; $126,000 for 2020; and $46,000 thereafter. For more information about options issued and outstanding, refer to Note 8 of the September 30, 2019 condensed financial statements.

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

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Depletion and depreciation	**22,973**	21,865	22,288	**66,143**	68,264
Exploration and evaluation	**-**	-	-	**-**	291

The provision for depletion and depreciation decreased in the first nine months of 2019 compared to the same period in 2018 due to decreased production volumes.

The E&E expense for the nine months ended September 30, 2018 was related to expired leases.

There were no impairment provisions recorded for the three and nine month periods ended September 30, 2019 or 2018.

Taxes

The Company recorded a deferred income tax recovery of $19,382,000 (2018 – $7,570,000 expense). The deferred income tax recovery is due to a decrease in the Alberta corporate income tax rate from 12 percent to 8 percent by January 1, 2022.

For additional information regarding income taxes, see Note 7 of the September 30, 2019 condensed financial statements.

Net Earnings (Loss)

($ 000s except $ per share)	September 30, 2019	Three months ended June 30, 2019	September 30, 2018	Nine months ended September 30, 2019	September 30, 2018
Net earnings (loss)	**(1,276)**	23,131	5,756	**23,312**	18,076
$ per share - basic	**(0.04)**	0.69	0.17	**0.70**	0.54
$ per share - diluted	**(0.04)**	0.69	0.17	**0.70**	0.54

Net earnings for the first nine months of 2019 increased by $5,236,000 compared to 2018. The increase in net earnings was attributed to the deferred income tax recovery as a result of a decrease in the Alberta corporate income tax rate. In addition, royalties and depletion and depreciation were lower given the decrease in realized commodity prices and production, respectively. The increase in net earnings for the first nine months of 2019 was partially offset by a decrease in oil and gas sales.

The quarter-over-quarter decrease in net earnings was mainly due to a deferred income tax recovery provision recorded in Q2 2019, and the decrease in production and oil prices in Q3 2019 compared to the prior quarter.

Other Comprehensive Income (Loss)

Other comprehensive income for 2019 consists of an unrealized loss before tax on investments (including investment in a related party) of $109,000 relating to a decrease in the investments' fair value (September 30, 2018 – unrealized loss of $221,000). 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)	September 30, 2019	Three months ended June 30, 2019	September 30, 2018	Nine months ended September 30, 2019	September 30, 2018
Cash flow from operations	**19,774**	25,468	33,669	**60,365**	95,454
$ per share - basic	**0.59**	0.76	1.01	**1.81**	2.87
$ per share - diluted	**0.59**	0.76	1.01	**1.81**	2.87

In the first nine months of 2019, cash flow from operations decreased by $35,089,000 compared to the same period a year ago. This was primarily due to a decrease in revenue from oil and gas sales.

The quarter-over-quarter decrease in cash flow of $5,694,000 is also primarily due to a decrease in revenue from oil and gas sales.

Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2018 – 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 September 30, 2019 of $134,000 (December 31, 2018 – $258,000). The Company provides marketing services for Pine Cliff. All services performed were charged at estimated fair value. As at September 30, 2019, the Company had an account receivable from Pine Cliff of $21,000 (December 31, 2018 – $71,000).

As at September 30, 2019, the Company's CEO, Chairman of the Board and major shareholder has loaned Bonterra $12,000,000 (December 31, 2017 - $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of one percent and has no set repayment terms but is payable on demand. Security under the debenture is over all the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan for the first nine months of 2019 was $298,000 (September 30, 2018 - $261,000). 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 September 30, 2019 was 4.5 to 1 times (versus 2.8 to 1 times at December 31, 2018). The higher net debt to cash flow ratio stems from a decrease in the twelve-month trailing cash flow. Compared to year end 2018, net debt decreased by $20,872,000 in the first nine months of 2019 due to a stronger focus on debt reduction, a decrease in capital spending and reduced dividend payments compared to the prior period. The Company's primary focus remains on managing its bank debt during a period of highly 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)	**September 30, 2019**	June 30, 2019	December 31, 2018	September 30, 2018
Working capital deficiency	**24,599**	22,238	30,281	35,319
Long-term bank debt	**283,470**	288,545	298,660	293,197
Net Debt	**308,069**	310,783	328,941	328,516

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 September 30, 2019 decreased by $20,447,000 compared to September 30, 2018 primarily due to higher realized crude oil prices, execution of a successful capital program and a reduction in the monthly dividend.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and adjustments of dividend payments. Included in the working capital deficiency as at September 30, 2019 is $19,500,000 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. During the third quarter of 2019, the Company also entered into risk management contracts to manage commodity risk. These contracts are not considered normal sales contracts and are recorded at fair value. For more information on physical delivery and risk management contracts in place see Note 10 of the September 30, 2019 condensed financial statements.

Capital Expenditures

During the nine months ended September 30, 2019, the Company incurred capital expenditures of $47,949,000 (September 30, 2018 - $73,952,000). Of the total capital invested, $41,470,000 was directed to drilling and completing 26 gross (20.6 net) wells and tying-in 24 gross (18.6 net) wells. An additional $6,479,000 was spent on related infrastructure costs, recompletions and other capital expenditures. The Company anticipates ending the year at the low end of its annual capital guidance of $57,000,000 to $77,000,000 for 2019.

Liability Management Ratio ("LMR") Update

In the first nine months of 2019, 95 percent of the Company's production was in the province of Alberta. The Company currently has an LMR rating of 1.89 in Alberta, which has decreased from the beginning of the year as lower drilling activity has led to lower production volumes and a lower three-year average for crude oil pricing. Bonterra does not anticipate any regulatory impediments given its current LMR.

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 September 30, 2019, the Company has a bank facility with a limit of $340,000,000 (December 31, 2018 - $380,000,000) that is comprised of a $300,000,000 syndicated revolving credit facility and a $40,000,000 non-syndicated revolving credit facility which has an accordion feature allowing the Company to obtain future funding of up to $40,000,000 for opportunities outside of normal operations, such as acquisitions, subject to unanimous lender approval. Amounts drawn under the bank facility of $340,000,000 at September 30, 2019 totaled $283,470,000 (December 31, 2018 - $298,660,000), five percent lower than year-end 2018. The interest rates for the nine months ended September 30, 2019 on the Company's Canadian prime rate loan and Banker's Acceptances are between four to six percent. The loan is revolving to April 28, 2020 with a maturity date of April 29, 2021, 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. Effective October 31, 2019, the total credit facility was revised to $325,000,000, comprised of a $286,765,000 syndicated revolving credit facility and a $38,235,000 non-syndicated revolving credit facility. All other terms and conditions remain the same.

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 6 of the September 30, 2019 condensed financial statements.

Shareholders' Equity

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

The Company is also 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.

Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**
Balance, September 30, 2019 and December 31, 2018	**33,388,796**	**765,276**

The Company provides a stock option plan for its directors, officers and employees. Under the plan, the Company may grant options for up to 3,338,880 (December 31, 2018 – 3,338,880) 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 8 of the September 30, 2019 condensed financial statements.

Dividend Policy

For the three months ended September 30, 2019, the Company declared and paid dividends of $1,002,000 ($0.03 per share) (September 30, 2018 – $9,994,000) ($0.30 per share). For the nine months ended September 30, 2019 the Company declared and paid dividends of $3,005,000 ($0.09 per share) (September 30, 2018 - $29,980,000 ($0.90 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. Bonterra's dividend payout ratio based on cash flow from operations was five percent for the nine months ended September 30, 2019 (31 percent for the nine months ended September 30, 2018).

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 while giving 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

	2019			2018			
For the periods ended ($ 000s except $ per share)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	**47,320**	54,852	49,834	34,988	63,817	67,458	57,124
Cash flow from operations	**19,774**	25,468	15,123	20,509	33,669	31,908	29,877
Net earnings (loss)	**(1,276)**	23,131	1,457	(10,909)	5,756	8,925	3,395
Per share - basic	**(0.04)**	0.69	0.04	(0.33)	0.17	0.27	0.10
Per share - diluted	**(0.04)**	0.69	0.04	(0.33)	0.17	0.27	0.10

	2017			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	54,192	46,349	52,695	49,330
Cash flow from operations	26,472	25,491	27,370	24,540
Net 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, the Canadian oil and gas industry realized a significant decrease in realized commodity prices for crude oil, which negatively impacted Q4 2018 net earnings and cash flow, as well as Q1 2019 cash flow. Net earnings for Q2 2019 increased due to a deferred tax recovery from a decrease in the Alberta corporate income tax rate.

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.

Internal Controls Over Financial Reporting

The Company is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings." The certification of interim filings for the interim period ended September 30, 2019 requires that Bonterra disclose in the interim MD&A any changes in the Company's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. Bonterra confirms that no such changes were made to its internal controls over financial reporting during the nine months ended September 30, 2019.

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