For the Three and Six Months ended June 30, 2019

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BONTERRA ENERGY REPORTS SECOND QUARTER AND SIX MONTHS ENDED JUNE 30, 2019 FINANCIAL AND OPERATING RESULTS

HIGHLIGHTS

		Three months ended		Six months ended	
As at and for the periods ended		**June 30,**	June 30,	**June 30,**	June 30,
($ 000s except for $ per share and $ per BOE)		**2019**	2018	**2019**	2018
FINANCIAL					
Revenue - realized oil and gas sales		**54,852**	67,458	**104,686**	124,583
Funds flow [1]		**26,247**	37,642	**50,610**	65,601
Per share - basic and diluted		**0.79**	1.13	**1.52**	1.97
Dividend payout ratio		**4%**	27%	**4%**	30%
Cash flow from operations		**25,468**	31,908	**40,591**	61,785
Per share - basic and diluted		**0.76**	0.96	**1.22**	1.85
Dividend payout ratio		**4%**	31%	**5%**	32%
Cash dividends per share		**0.03**	0.30	**0.06**	0.60
Net earnings		**23,131**	8,925	**24,588**	12,320
Per share - basic and diluted		**0.69**	0.27	**0.74**	0.37
Capital expenditures, net of dispositions		**9,042**	18,970	**30,104**	55,138
Total assets				**1,123,513**	1,147,501
Working capital deficiency				**22,238**	27,069
Long-term debt				**288,545**	303,413
Shareholders' equity				**507,659**	503,979
OPERATIONS					
Oil	-barrels per day	**7,746**	8,743	**7,416**	8,391
	-average price ($ per barrel)	**71.27**	76.51	**68.23**	72.35
NGLs	-barrels per day	**970**	984	**960**	942
	-average price ($ per barrel)	**25.53**	43.69	**28.41**	41.32
Natural gas	- MCF per day	**23,750**	25,317	**23,843**	25,011
	- average price ($ per MCF)	**1.09**	1.16	**1.89**	1.69
Total barrels of oil equivalent per day (BOE) [2]		**12,674**	13,946	**12,349**	13,501

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

(2) 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") is pleased to report its financial and operational results for the second quarter and first half of 2019. Although Western Canadian producers have generally benefited from improved oil prices and narrower differentials for Canadian sweet crude oil following the Government of Alberta's mandated curtailment that took effect in January, volatility in oil prices has continued into the third quarter.

During the first half of 2019, Bonterra remained focused on balancing its debt reduction strategy with the prudent development of its high-quality, light oil-weighted Pembina and Willesden Green Cardium assets. By June 30, 2019, Bonterra had successfully reduced its net debt by six percent, or $18.2 million, compared to year end 2018. The Company's maintenance capital requirements are modest due to having a low annual production decline rate of approximately 20 percent. With Bonterra's current Canadian realized oil price ranging from $60 to $70 per bbl, and its continued prioritization of cost control initiatives designed to optimize netbacks, the Company has the ability to generate substantial free cash flow to be allocated to reducing net debt, and may be used to adjust the monthly dividend in the future. As the balance sheet is strengthened, Bonterra's ability to shift capital from debt repayment to other opportunities such as growth, acquisitions or dividend changes is greatly enhanced.

Following are highlights from the Company's second quarter and first half of 2019:

- Reduced net debt to $310.8 million at quarter end, representing a six percent reduction from $328.9 million at December 31, 2018, and a five percent reduction from $326.7 million at March 31, 2019.
- Generated funds flow of $26.2 million ($0.79 per share) in Q2 2019, a seven percent increase from Q1 2019, and a 30 percent decrease compared to Q2 2018, which had higher production and stronger benchmark pricing.
- Invested $27.2 million in net capital expenditures through the first half of 2019 to drill 14 gross (13.1 net) horizontal wells, completing and tying-in 13 gross (12.1 net) wells, with the remaining well being placed on production in July 2019. An additional $2.9 million was directed to related infrastructure costs, recompletions and other capital expenditures.
- Recorded net earnings for Q2 2019 of $23.1 million compared to $8.9 million for the same period in 2018, attributable to Alberta's corporate income tax rate decrease which produced a deferred income tax recovery.
- Averaged 12,674 BOE per day of production in Q2 2019, a quarter-over-quarter increase of 654 BOE per day, and approximately nine percent lower than the same period in 2018. The decrease year-over-year is due to reduced capital spending from using one drilling rig in 2019, compared to two drilling rigs for the comparable period in 2018 leading to fewer wells coming on line. The decrease was further inflated by shut-in production throughout the period because of a downstream third-party pipeline failure, early spring freeze offs, and pressure issues from new wells backing out existing wells.
- Increased field netbacks to $28.63 per BOE from $27.51 per BOE in Q1 2019, due to higher gross production revenue and lower royalties.
- Declared and paid out $0.03 per share in cash dividends to shareholders in the second quarter, resulting in a payout ratio of five percent of funds flow and bringing the year to date total paid to $0.06 per share.

With some strengthening in prices during Q2 2019, the Company took the opportunity to enter into physical delivery sales and risk management contracts for Q3 and Q4 2019, to receive an average MSW price on crude oil between C$65.00 and C$77.35 per bbl, for a portion of production until December 31, 2019. Such contracts help to reduce the impact of highly volatile market pricing by protecting revenue and related funds flow for the second half of 2019. Bonterra will continue to regularly review further opportunities to reduce exposure to pricing fluctuations for future periods where attractive prices can be locked in.

During the second quarter, the Company's syndicate of Canadian financial institutions renewed its borrowing base and in concert with Bonterra, determined that amending the Company's credit facilities would better reflect its current operating needs and strategy. The amended credit facilities are comprised of a $300 million syndicated revolving credit facility and a $40 million non-syndicated revolving credit facility with the addition of an accordion feature to allow the Company to obtain future funding of up to $40 million for opportunities, such as acquisitions. At June 30, 2019, Bonterra had drawn $288.5 million on the Company's $340 million credit facility.

Outlook

Bonterra's original 2019 capital budget of $57 to $77 million remains unchanged, which is designed to maintain an appropriate balance between funds flow and capital spending, with the ability to direct any excess funds flow to strengthening the balance sheet. Average annual production volumes in 2019 are forecast to be at the low end of the guidance range of 12,600 to 13,200 BOE per day, of which approximately 62 percent would be light, sweet crude oil.

Financial discipline and cost control continue to be priorities for Bonterra, and the Company will focus on further debt reduction to strengthen its balance sheet. With one of the lowest annual production decline rates and one of the largest inventories of low-risk, economic undrilled locations, Bonterra is well positioned to continue returning capital to shareholders in the form of sustainable dividends, while focusing on measured per share growth in cash flow, production and reserves.

Thank you again for your continued support.

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

Management's Discussion and Analysis

The following report dated August 7, 2019 is a review of the operations and current financial position for the three and six months ended June 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

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

As at and for the periods ended ($ 000s except $ per share)	2017 Q4	2017 Q3	2017 Q2	2017 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.

	Q2-2019	Q1-2019	Q4-2018	Q3-2018	Q2-2018	Q1-2018	Q4-2017	Q3-2017
Crude oil								
WTI (U.S.$/bbl)	**59.81**	54.90	58.81	69.50	67.88	62.87	55.40	48.30
WTI to MSW Stream Index								
Differential (U.S.$/bbl)[1]	**(4.62)**	(4.85)	(26.30)	(6.83)	(5.45)	(5.89)	(1.14)	(2.89)
Foreign exchange								
U.S.$ to Cdn$	**1.3375**	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717	1.2524
Bonterra average realized								
oil price (Cdn$/bbl)	**71.27**	64.87	38.96	77.20	76.51	67.78	65.16	53.48
Natural gas								
AECO (Cdn$/mcf)	**1.03**	2.61	1.55	1.19	1.18	2.07	1.68	1.45
Bonterra average realized								
gas price (Cdn$/mcf)	**1.09**	2.70	1.77	1.37	1.16	2.24	1.90	1.81

(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;
- Weather; and
- Timing and duration of plant, refinery and pipeline maintenance.

WTI benchmark pricing continues to be highly volatile, as uncertainties around both global supply and demand have contributed to the crude oil price volatility. Concern about weak demand in 2019, comes from a variety of factors, including but not limited to global trade issues between the US and China. Regarding supply, there is uncertainty whether crude oil supply growth will outpace cuts that were recently extended by OPEC and several non-OPEC nations, such as shale oil growth in the US. In Canada, volatility is even greater as pipeline capacity has not kept pace with production growth. This has led to continuous apportionment on feeder and export pipelines. In Q4 2018, this also led to excessive price weakness for Canadian oil, discounting it relative to the US and global benchmarks. Crude curtailments mandated by the Alberta Government at that time, along with incremental rail and seasonal factors have resulted in a significant narrowing of the differential for all grades of Canadian crude.

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. Additional shipments by rail are expected to continue throughout 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 the lack of pipeline capacity.

The AECO benchmark price for natural gas softened significantly in the second 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. It is expected that prices will remain depressed in the near term as supply continues to exceed pipeline capacity and local demand. Pricing instability should ease moving into the latter half 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 provide positive reinforcement to the negative 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 ($/bbl)	1.00	2,843	0.09
Realized natural gas price ($/mcf)	0.10	1,007	0.03
U.S.$ to Canadian $ exchange rate	0.01	1,507	0.05

(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

In the first half of 2019, Bonterra continued with its debt reduction strategy by decreasing net debt by $18,158,000 or six percent over net debt levels as at December 31, 2018.

Bonterra remains focused on debt reduction and long-term sustainability. The Company offers upside exposure to the Pembina and Willesden Green Cardium areas with a high-quality asset base featuring a low production decline rate at approximately 20 percent and high-quality asset base through a large inventory of low-risk, economic undrilled locations. Coupled 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.

During the second quarter, Bonterra continued to develop its high quality, oil-weighted assets in the Pembina and Willesden Green Cardium pool of Alberta. For the first six months of 2019, Bonterra invested approximately $30,104,000 (representing 53 percent of the lower end of its $57,000,000 to $77,000,000 annual capital budget), of which $27,195,000 was directed to drill 14 gross (13.1 net) horizontal wells, complete 13 gross (12.1 net) wells and tie-in 13 gross (12.1 net) wells, of which the remaining one well was placed on production early in July 2019. An additional $2,909,000 was spent on related infrastructure costs, recompletions and other capital expenditures.

For Q2 2019, production averaged 12,674 BOE per day. Shut-in production was approximately 360 BOE per day due to a downstream third-party pipeline failure, early spring freeze offs, and pressure issues from new wells backing out existing wells. The Company is trending to the low end annual production guidance of 12,600 BOE per day to 13,200 BOE per day. Production volumes will vary depending on the level of capital invested and commodity prices.

The Company benefitted from a stronger commodity price environment in both Q1 and Q2 2019 over Q4 2018 as extremely large differentials on Canadian sweet crude oil narrowed significantly after curtailments were put in place by the Alberta Government in January 2019. To partially protect production revenue and related cash flow for Q3 and Q4 2019, and to minimize the effects of potential declining commodity prices, the Company entered into physical delivery sales contracts. For Q3 2019, the Company will receive an average minimum MSW price on crude oil of $77.35 CAD per bbl for 1,000 bbls per day and will receive an average MSW price on crude oil of $67.75 CAD per bbl on an additional 1,000 bbls per day from September 1 to December 31, 2019. In addition, the Company entered into a risk management contract to receive an average MSW price on crude oil of $65.00 CAD per bbl on 500 bbls per day for Q4 2019.

On May 21, 2019, Bonterra renewed its borrowing base with its syndicate of lenders. The amended credit facilities of $340 million are comprised of a $300 million syndicated revolving credit facility (previously $330 million), a $40 million non-syndicated revolving credit facility (previously $50 million) and the addition of an accordion feature which allows the Company to obtain future funding of up to $40 million for opportunities outside of normal operations, such as acquisitions, subject to unanimous lender approval. Bonterra set its capital expenditure budget for 2019 with flexibility to adjust spending based on commodity prices. As a result, the amended credit facilities afford the Company with ample liquidity and sufficient financial flexibility to execute its business plan, which mainly includes directing free funds flow to ongoing debt repayment.

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						Six months ended			
		June 30, 2019		March 31, 2019		June 30, 2018		**June 30, 2019**		June 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	**2**	**2.0**	11	11.0	5	5.0	**13**	**13.0**	20	19.9
Crude oil horizontal-non-operated	**-**	**-**	1	0.1	-	-	**1**	**0.1**	2	0.2
Total	**2**	**2.0**	12	11.1	5	5.0	**14**	**13.1**	22	20.1
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 six months of 2019, the Company drilled 13 gross (13.0 net) wells, completed 12 gross (12.0 net) wells, of which 12 gross (12.0 net) wells were tied-in and placed on production. The remaining one gross (1.0 net) well commenced production in July 2019.

In addition, one gross (0.1 net) non-operated well was drilled, completed, equipped and placed on production during the first six months of 2019.

Production

	Three months ended			Six months ended	
	June 30, 2019	March 31, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
Crude oil (barrels per day)	**7,746**	7,081	8,743	**7,416**	8,391
NGLs (barrels per day)	**970**	949	984	**960**	942
Natural gas (MCF per day)	**23,750**	23,938	25,317	**23,843**	25,011
Average BOE per day	**12,674**	12,020	13,946	**12,349**	13,501

The Company averaged 12,349 BOE per day for the first six months of 2019, compared to 13,501 BOE per day for the same period in 2018. The decrease in production for the first six months of 2019, is the result of significantly reduced capital spending from using one drilling rig in 2019, compared to two drilling rigs for the comparable period in 2018, leading to fewer wells coming on line. In addition for the first six months of 2019, an average of approximately 460 BOE per day of production has been shut-in primarily due to freeze-offs from extremely cold winter weather, pressure issues from new wells backing out existing wells, a downstream third-party pipeline failure and third-party maintenance programs. Some of these shut-in production issues have been resolved with warmer weather, completion of third-party repairs and maintenance programs and infrastructure to add compression.

Quarter-over-quarter production increased from new wells placed on production late in the first quarter and early in the second quarter. This was partially offset by 360 BOE per day of shut-in production through the period caused primarily by a downstream third-party pipeline failure, early spring freeze-offs and pressure issues from new wells backing out existing wells.

Cash Netback

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

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
$ per BOE	**2019**	2019	2018	**2019**	2018
Production volumes (BOE)	**1,153,375**	1,081,807	1,269,114	**2,235,182**	2,443,713
Gross production revenue	**47.56**	46.07	53.15	**46.84**	50.98
Royalties	**(3.05)**	(3.71)	(5.45)	**(3.37)**	(5.19)
Production costs	**(15.88)**	(14.85)	(13.01)	**(15.38)**	(13.73)
Field netback	**28.63**	27.51	34.69	**28.09**	32.06
General and administrative	**(1.95)**	(1.42)	(1.67)	**(1.69)**	(1.70)
Interest and other	**(3.52)**	(3.56)	(2.96)	**(3.54)**	(3.31)
Cash netback	**23.16**	22.53	30.06	**22.86**	27.05

Cash netbacks decreased in the first six months of 2019 compared to 2018 primarily due to decreased commodity prices and increased production costs, which was partially offset by a decrease in royalties.

Cash netbacks for Q2 2019 compared to Q1 2019 increased due to higher realized crude oil prices and a decrease in the royalty rate for gas and NGL crown royalties, which was partially offset by an increase in productions costs.

Oil and Gas Sales

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
	2019	2019	2018	**2019**	2018
Revenue - oil and gas sales ($ 000s)					
Crude oil	**50,235**	41,343	60,869	**91,578**	109,879
NGL	**2,253**	2,682	3,912	**4,935**	7,047
Natural gas	**2,364**	5,809	2,677	**8,173**	7,657
	54,852	49,834	67,458	**104,686**	124,583
Average realized prices:					
Crude oil ($ per barrel)	**71.27**	64.87	76.51	**68.23**	72.35
NGLs ($ per barrel)	**25.53**	31.40	43.69	**28.41**	41.32
Natural gas ($ per MCF)	**1.09**	2.70	1.16	**1.89**	1.69
Average ($ per BOE)	**47.56**	46.07	53.15	**46.84**	50.98
Average BOE per day	**12,674**	12,020	13,946	**12,349**	13,501

Revenue from oil and gas sales in the first six months of 2019 decreased by $19,897,000, or 16 percent, compared to 2018. The decrease in oil and gas sales was primarily driven by a nine percent decrease in production volumes and a decrease in commodity prices for oil and NGLs. The quarter-over-quarter increase in oil and gas sales was primarily due to an increase in crude oil prices and increased production volumes compared to Q1 2019.

The Company's product split on a revenue basis for 2019 is weighted approximately 92 percent to crude oil and NGLs.

Royalties

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Crown royalties	**1,683**	2,204	4,090	**3,887**	7,897
Freehold, gross overriding and other royalties	**1,832**	1,810	2,820	**3,642**	4,795
Total royalties	**3,515**	4,014	6,910	**7,529**	12,692
Crown royalties - percentage of revenue	**3.1**	4.4	6.1	**3.7**	6.3
Freehold, gross overriding and other royalties - percentage of revenue	**3.3**	3.6	4.2	**3.5**	3.8
Royalties - percentage of revenue	**6.4**	8.0	10.3	**7.2**	10.1
Royalties $ per BOE	**3.05**	3.71	5.45	**3.37**	5.19

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 $1.82 per BOE for the first six months of 2019 compared to 2018. The decrease in royalties is primarily a result of declining commodity prices. The quarter-over-quarter decrease in royalties of $0.66 per BOE was primarily due to reduced royalties on gas and NGLs from lower commodity prices and a gas cost allowance recovery on natural gas crown royalties.

Production Costs

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per BOE)	**2019**	2019	2018	**2019**	2018
Production costs	**18,312**	16,068	16,517	**34,380**	33,543
$ per BOE	**15.88**	14.85	13.01	**15.38**	13.73

Production costs over the first six months of 2019 increased by $837,000 compared to 2018 primarily due to trucking costs associated with flush production exceeding facility capacity from new drills. Trucking costs are expected to decrease as the new well production stabilizes. Facility maintenance also increased in the second quarter as additional multi-year gas plant and battery turnarounds were completed in the second quarter instead of the third quarter. The Company also incurred increased power costs from the retirement of coal-fired power generation facilities in Alberta effective April 1, 2018. This was partially offset by a decrease in gathering, processing, treating and disposal costs due to lower production volumes.

Production costs for Q2 2019 increased by $2,244,000 compared to Q1 2019 primarily due to oil and water trucking from new well production and facility turnarounds.

Other Income

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Investment income	**21**	11	(72)	**32**	27
Administrative income	**30**	25	42	**55**	94
Deferred consideration	**304**	322	383	**626**	728
Gain on sale of property	**-**	2	-	**2**	-
	355	360	353	**715**	849

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 June 30, 2019 was $287,000 (June 30, 2018 - $608,000). There were no dispositions for the six months ended June 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.

General and Administration (G&A) Expense

($ 000s except $ per BOE)	Three months ended June 30, 2019	Three months ended March 31, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Employee compensation expense	**1,119**	1,096	1,370	**2,215**	2,735
Office and administrative expense	**1,131**	438	747	**1,569**	1,412
Total G&A expense	**2,250**	1,534	2,117	**3,784**	4,147
$ per BOE	**1.95**	1.42	1.67	**1.69**	1.70

The decrease of $520,000 in employee compensation expense for the first six 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. 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 the first six months of 2019 increased by $157,000 compared to 2018 primarily due to an increase in software, consulting fees and insurance costs in Alberta. The increase was partially offset by a decrease in bank charges and the allowance for doubtful accounts expense. The increase in Q2 2019 over Q1 2019 was primarily due to the bank renewal fees incurred in the second quarter and increased professional consulting fees.

Finance Costs

($ 000s except $ per BOE)	Three months ended June 30, 2019	Three months ended March 31, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Interest on long-term debt	**3,919**	3,698	3,504	**7,617**	7,764
Other interest	**192**	193	217	**385**	436
Interest expense	**4,111**	3,891	3,721	**8,002**	8,200
$ per BOE	**3.56**	3.60	2.93	**3.58**	3.36
Unwinding of the discounted value of decommissioning liabilities	**747**	743	761	**1,490**	1,518
Total finance costs	**4,858**	4,634	4,482	**9,492**	9,718

Interest on long-term debt decreased in the first six months of 2019 compared to the first six months of 2018 due to the Company having a lower average long-term debt outstanding of approximately $4,210,000. Quarter-over-quarter interest on long-term debt increased as a result of a higher net debt to EBITDA ratio for Q4 2018 which was in effect during Q2 2019. The Company expects interest rates on long-term debt will decrease in Q3 2019 due to an improved net debt to EBITDA ratio from higher realized oil pricing compared to Q4 2018. 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 June 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 $2,209,000.

Share-Option Compensation

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Share-option compensation	**620**	559	766	**1,179**	1,508

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 $329,000 in the first six 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) have a higher share price volatility than the options issued in the fourth quarter of 2018 (which will be amortized in 2019).

Based on the outstanding options as of June 30, 2019, the Company has an unamortized expense of $1,033,000, of which $861,000 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 June 30, 2019 condensed financial statements.

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

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2019**	2019	2018	**2019**	2018
Depletion and depreciation	**21,865**	21,305	24,526	**43,170**	45,976
Exploration and evaluation	**-**	-	-	**-**	291

The provision for depletion and depreciation decreased in the first half of 2019 compared to 2018 due to decreased production volumes.

The E&E expense was related to expired leases.

There were no impairment provisions recorded for the three and six months ended June 30, 2019 and 2018.

Taxes

The Company recorded a deferred income tax recovery of $19,189,000 (2018 – $4,716,000 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 June 30, 2019 condensed financial statements.

Net Earnings (Loss)

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per share)	**2019**	2019	2018	**2019**	2018
Net earnings (loss)	**23,131**	1,457	8,925	**24,588**	12,320
$ per share - basic	**0.69**	0.04	0.27	**0.74**	0.37
$ per share - diluted	**0.69**	0.04	0.27	**0.74**	0.37

Net earnings for the first six months of 2019 increased by $12,268,000 compared to 2018. The increase in net earnings was mainly due to the deferred income tax recovery as a result of the decrease in the Alberta corporate income tax rate. In addition, royalties and depletion and depreciation are lower given the decrease in realized commodity prices and production respectively. The increase in net earnings was partially offset by a decrease in oil and gas sales and an increase in production costs.

The quarter-over-quarter increase in net earnings was mainly due to the deferred income tax recovery provision and improved production and oil commodity prices.

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 $88,000 relating to a decrease in the investments' fair value (June 30, 2018 – unrealized loss of $142,000). Realized gains decrease accumulated other comprehensive income as these gains are transferred to retained earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments, including the investment in a related party, net of tax.

Cash Flow from Operations

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per share)	**2019**	2019	2018	**2019**	2018
Cash flow from operations	**25,468**	15,123	31,908	**40,591**	61,785
$ per share - basic	**0.76**	0.45	0.96	**1.22**	1.85
$ per share - diluted	**0.76**	0.45	0.96	**1.22**	1.85

In the first half of 2019, cash flow from operations decreased by $21,194,000 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 increase in cash flow of $10,345,000 is primarily due to an increase in non-cash working capital and 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 June 30, 2019 of $176,000 (December 31, 2018 – $258,000). The Company provides marketing services for Pine Cliff. All services performed were charged at estimated fair value. As at June 30, 2019, the Company had an account receivable from Pine Cliff of $32,000 (December 31, 2018 – $71,000).

As at June 30, 2019, 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 5/8th 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 six months of 2019 was $198,000 (June 30, 2018 - $167,000). 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 June 30, 2019 was 3.7 to 1 times (versus 2.8 to 1 times at December 31, 2018). The increase in net debt to cash flow ratio is due to a decrease in the twelve-month trailing cash flow. Net debt decreased by $18,158,000 in the first six months of 2019 due to a stronger focus on debt reduction by a decrease in capital spending in a very volatile commodity market and reduced dividend payments compared to the prior period. 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)	**June 30, 2019**	March 31, 2019	December 31, 2018	June 30, 2018
Working capital deficiency	**22,238**	30,139	30,281	27,069
Long-term bank debt	**288,545**	296,594	298,660	303,413
Net Debt	**310,783**	326,733	328,941	330,482

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 June 30, 2019 decreased by $19,699,000 compared to June 30, 2018 primarily due to an increase in cash flow from a successful capital program in the first nine months of 2018 and a conservative capital program following decreased cash flow in Q4 2018 from depressed realized Canadian crude oil prices. The Company also reduced the monthly dividend in December 2018 from $0.10 to $0.01 per share.

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 June 30, 2019 is $19,500,000 million of debt relating to the subordinated promissory note and the amount due to a related party.

Financial Risk Management

The Company has entered into physical delivery sales contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the financial statements. Subsequent to June 30, 2019, the Company has also entered into a risk management contract to manage commodity risk. This contract is not considered a normal sales contract and is recorded at fair value. For more information on physical delivery and risk management contracts in place see Note 10 of the June 30, 2019 condensed financial statements.

Capital Expenditures

During the six months ended June 30, 2019, the Company incurred capital expenditures of $30,104,000 (June 30, 2018 - $55,138,000). The costs primarily relate to $27,195,000 for drilling 14 gross (13.1 net) wells, completing 13 gross (12.1 net) wells and tying-in 13 gross (12.1 net) wells. An additional $2,909,000 was spent on related infrastructure costs, recompletions and other capital expenditures. It is anticipated that the Company will be at the low end of its annual capital budget of $57,000,000 to $77,000,000 for 2019.

Liability Management Ratio ("LMR") Update

In the first six months of 2019, 95 percent of the Company's production was in the province of Alberta. The Company currently has an LMR rating of 1.94 in Alberta, which has decreased from the beginning of the year as lower drilling activity resulted in lower production volumes. Bonterra does not expect that there to be any regulatory impediments to completing future potential acquisitions 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 June 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 and the addition of an accordion feature which allows 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 June 30, 2019 totaled $288,545,000 (December 31, 2018 - $298,660,000). The interest rates for the six months ended June 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.

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 June 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, June 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 June 30, 2019 condensed financial statements.

Dividend Policy

For the three months ended June 30, 2019, the Company declared and paid dividends of $1,001,000 ($0.03 per share) (June 30, 2018 – $9,993,000) ($0.30 per share). For the six months ended June 30, 2019 the Company declared and paid dividends of $2,003,000 ($0.06 per share) (June 30, 2018 - $19,986,000 ($0.60 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 six months ended June 30, 2019 (32 percent for the six months ended June 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)	**Q2**	Q1	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	**54,852**	49,834	34,988	63,817	67,458	57,124
Cash flow from operations	**25,468**	15,123	20,509	33,669	31,908	29,877
Net earnings (loss)	**23,131**	1,457	(10,909)	5,756	8,925	3,395
Per share - basic	**0.69**	0.04	(0.33)	0.17	0.27	0.10
Per share - diluted	**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 June 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 six months ended June 30, 2019.

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

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

The audit committee has reviewed these condensed financial statements with management and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this interim report.

CONDENSED STATEMENT OF FINANCIAL POSITION

As at (unaudited) ($ 000s)	Note	**June 30, 2019**	December 31, 2018
Assets			
Current			
Accounts receivable		**17,293**	7,797
Crude oil inventory		**582**	613
Prepaid expenses		**5,960**	3,183
Investments		**111**	116
		23,946	11,709
Investment in related party		**176**	258
Exploration and evaluation assets		**4,422**	4,422
Property, plant and equipment	3	**993,298**	985,773
Investment tax credit receivable	7	**8,861**	8,861
Goodwill		**92,810**	92,810
		1,123,513	1,103,833
Liabilities			
Current			
Accounts payable and accrued liabilities		**25,485**	18,743
Due to related party	4	**12,000**	12,000
Subordinated promissory note	5	**7,500**	10,000
Deferred consideration		**1,199**	1,247
		46,184	41,990
Bank debt	6	**288,545**	298,660
Deferred consideration		**12,876**	13,455
Decommissioning liabilities		**153,826**	132,134
Deferred tax liability	7	**114,423**	133,624
		615,854	619,863
Subsequent events	10, 11		
Shareholders' equity			
Share capital	8	**765,276**	765,276
Contributed surplus		**29,266**	28,087
Accumulated other comprehensive loss		**(739)**	(664)
Retained earnings (deficit)		**(286,144)**	(308,729)
		507,659	483,970
		1,123,513	1,103,833

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF COMPREHENSIVE INCOME

For the periods ended June 30 (unaudited)		Three Months		Six Months	
($ 000s, except $ per share)	Note	**2019**	2018	**2019**	2018
Revenue					
Oil and gas sales, net of royalties	9	**51,337**	60,548	**97,157**	111,891
Other income		**51**	(30)	**89**	121
Deferred consideration		**304**	383	**626**	728
		51,692	60,901	**97,872**	112,740
Expenses					
Production		**18,312**	16,517	**34,380**	33,543
Office and administration		**1,131**	747	**1,569**	1,412
Employee compensation		**1,119**	1,370	**2,215**	2,735
Finance costs		**4,858**	4,482	**9,492**	9,718
Share-option compensation		**620**	766	**1,179**	1,508
Depletion and depreciation	3	**21,865**	24,526	**43,170**	45,976
Exploration and evaluation		**-**	-	**-**	291
		47,905	48,408	**92,005**	95,183
Earnings before income taxes		**3,787**	12,493	**5,867**	17,557
Taxes					
Current income tax expense		**468**	521	**468**	521
Deferred income tax expense (recovery)	7	**(19,812)**	3,047	**(19,189)**	4,716
		(19,344)	3,568	**(18,721)**	5,237
Net earnings for the period		**23,131**	8,925	**24,588**	12,320
Other comprehensive income (loss)					
Unrealized gain (loss) on investments		**(82)**	48	**(87)**	(142)
Deferred taxes on unrealized loss (gain) on investments		**11**	(7)	**12**	19
Other comprehensive income (loss) for the period		**(71)**	41	**(75)**	(123)
Total comprehensive income for the period		**23,060**	8,966	**24,513**	12,197
Net earnings per share - basic and diluted	8	**0.69**	0.27	**0.74**	0.37
Comprehensive income per share - basic and diluted	8	**0.69**	0.27	**0.73**	0.37

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF CASH FLOW

For the periods ended June 30 (unaudited)		Three Months		Six Months	
($ 000s)	Note	**2019**	2018	**2019**	2018
Operating activities					
Net earnings		**23,131**	8,925	**24,588**	12,320
Items not affecting cash					
Deferred income taxes		**(19,812)**	3,047	**(19,189)**	4,716
Deferred consideration		**(304)**	(383)	**(626)**	(728)
Share-option compensation		**620**	766	**1,179**	1,508
Depletion and depreciation		**21,865**	24,526	**43,170**	45,976
Exploration and evaluation expenditures		**-**	-	**-**	291
Gain on sale of property and equipment		**-**	-	**(2)**	-
Unwinding of the discount on decommissioning liabilities		**747**	761	**1,490**	1,518
Investment income		**(21)**	(14)	**(32)**	(27)
Interest expense		**4,111**	3,721	**8,002**	8,200
Change in non-cash working capital accounts:					
Accounts receivable		**2,635**	60	**(9,355)**	(2,189)
Crude oil inventory		**(11)**	(18)	**37**	48
Prepaid expenses		**(3,201)**	(3,867)	**(2,777)**	(3,658)
Accounts payable and accrued liabilities		**111**	(1,436)	**2,507**	2,679
Decommissioning expenditures		**(292)**	(459)	**(399)**	(669)
Interest paid		**(4,111)**	(3,721)	**(8,002)**	(8,200)
Cash provided by operating activities		**25,468**	31,908	**40,591**	61,785
Financing activities					
Decrease of bank debt		**(8,049)**	11,419	**(10,115)**	11,201
Subordinated promissory note		**-**	-	**(2,500)**	(2,500)
Dividends		**(1,001)**	(9,993)	**(2,003)**	(19,986)
Cash provided by (used) in financing activities		**(9,050)**	1,426	**(14,618)**	(11,285)
Investing activities					
Investment income received		**21**	14	**32**	27
Property, plant and equipment expenditures	3	**(9,042)**	(18,970)	**(30,104)**	(55,138)
Proceeds on sale of property		**-**	-	**5**	-
Change in non-cash working capital accounts:					
Accounts payable and accrued liabilities		**(7,436)**	(14,449)	**4,235**	3,628
Accounts receivable		**39**	71	**(141)**	983
Cash used in investing activities		**(16,418)**	(33,334)	**(25,973)**	(50,500)
Net change in cash in the period		**-**	-	**-**	-
Cash, beginning of period		**-**	-	**-**	-
Cash, end of period		**-**	-	**-**	-

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF CHANGES IN EQUITY

For the periods ended (unaudited)

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

	Numbers of common shares outstanding (Note 8)	Share Capital (Note 8)	Contributed surplus [1]	Accumulated other Comprehensive income (loss) [2]	Retained earnings (deficit)	Total shareholders' equity
January 1, 2018	33,310,796	763,977	25,533	(339)	(278,911)	510,260
Share-option compensation			1,508			1,508
Comprehensive income (loss)				(123)	12,320	12,197
Dividends					(19,986)	(19,986)
June 30, 2018	33,310,796	763,977	27,041	(462)	(286,577)	503,979
Share-option compensation			1,202			1,202
Exercise of options	78,000	1,143				1,143
Transfer to share capital on exercise of options		156	(156)			-
Comprehensive income (loss)				(202)	(5,153)	(5,355)
Dividends					(16,999)	(16,999)
December 31, 2018	33,388,796	765,276	28,087	(664)	(308,729)	483,970
Share-option compensation			1,179			1,179
Comprehensive income (loss)				(75)	24,588	24,513
Dividends					(2,003)	(2,003)
June 30, 2019	33,388,796	765,276	29,266	(739)	(286,144)	507,659

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

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

See accompanying notes to these condensed financial statements.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS

As at June 30, 2019 and December 31, 2018 and for the three and six months ended June 30, 2019 and June 30, 2018. (unaudited)

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 Canada Business Corporations Act. The address of the Company’s registered office is Suite 901, 1015-4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

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

The financial statements were authorized for issue by the Company’s Board of Directors on August 7, 2019.

2. BASIS OF PREPARATION

a) Statement of Compliance

The Company prepares its unaudited condensed financial statements in accordance with International Accounting Standard 34 – Interim Financial Reporting (IAS 34).

The accounting policies and method of computation followed in the preparation of the condensed financial statements are the same as those followed in the preparation of Bonterra’s 2018 audited annual financial statements, except for as denoted below. These condensed financial statements do not include all of the information required for annual financial statements and should be read in conjunction with the 2018 audited annual financial statements, which has been prepared in accordance with International Financial Reporting Standards (IFRS).

b) Adopted Accounting Pronouncements

IFRS 16 “Leases”

As of January 1, 2019, the Company adopted IFRS 16 which replaces sections IAS 17 “Leases”, IFRIC 4 “Determining whether an arrangement contains a lease”, SIC-15 “Operating leases – incentives” and SIC-27 “Evaluating the substance of transactions involving the legal form of a lease”. IFRS 16 introduces a single lease accounting model for lessees which requires the recognition of a right of use asset (“ROU”) and a lease liability on the statement of financial position for contracts that are, or contain, a lease.

The Company adopted IFRS 16 using the modified retrospective approach. Under this method of adoption, the ROUs recognized were measured at amounts equal to the present value of the lease obligations. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to opening retained earnings and applies the standard prospectively. The Company elected not to apply lease accounting to certain leases for which the lease term ends within 12 months of the date of initial adoption. The Company undertook a complete evaluation of the contracts it has entered into, and it was determined that there is no material impact as a result of adopting IFRS 16. In addition, as a result of this adoption, the Company has included an accounting policy for leases as follows:

Leases

Leases or contractual obligations are capitalized as ROUs with a corresponding right of use lease obligation using the present value of future lease payments on the statement of financial position. The discount rate used to determine the ROU is disclosed in the lease contract or the Company’s incremental borrowing rate, if none is provided. Certain lease payments will continue to be expensed in the statement of comprehensive income. These leases are contractual obligations that contain any of the following: are equal to or less than twelve months; are for oil and gas extraction; are variable payments; the Company does not control the asset; or no asset is identified in the lease.

IFRS 3 “Business Combinations”

The Company elected to early adopt the amendments to IFRS 3 "Business Combinations" effective January 1, 2019, which will be applied prospectively to acquisitions that occur on or after January 1, 2019. The amendments introduce an optional concentration test, narrow the definitions of a business and outputs, and clarify that an acquired set of activities and assets must include an input and a substantive process that together significantly contribute to the ability to create outputs. These amendments do not result in changes to the Company’s accounting policies for applying the acquisition method.

3. PROPERTY, PLANT AND EQUIPMENT

Cost ($ 000s)	**Oil and gas properties**	**Production facilities**	**Furniture fixtures & other equipment**	**Total property plant & equipment**
Balance at December 31, 2018	1,382,661	342,048	2,285	1,726,994
Additions	22,593	7,484	27	30,104
Adjustment to decommissioning liabilities [(1)]	20,600	-	-	20,600
Disposal	-	-	(33)	(33)
Balance at June 30, 2019	**1,425,854**	**349,532**	**2,279**	**1,777,665**

Accumulated depletion and depreciation ($ 000s)	**Oil and gas properties**	**Production facilities**	**Furniture fixtures & other equipment**	**Total property plant & equipment**
Balance at December 31, 2018	(604,502)	(134,927)	(1,792)	(741,221)
Depletion and depreciation	(35,482)	(7,631)	(57)	(43,170)
Disposal and other	(6)	-	30	24
Balance at June 30, 2019	**(639,990)**	**(142,558)**	**(1,819)**	**(784,367)**

Carrying amounts as at: ($ 000s)				
December 31, 2018	778,159	207,121	493	985,773
June 30, 2019	**785,864**	**206,974**	**460**	**993,298**

[(1)] Adjustment to decommissioning liabilities is due to a 0.36 percent 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 for the six months ended June 30, 2019 and 2018.

4. TRANSACTIONS WITH RELATED PARTIES

As at June 30, 2019, the Company’s CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2018 - $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 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 the first six months of 2019 was $198,000 (June 30, 2018 - $167,000).

The Company provides executive and marketing services for Pine Cliff Energy Ltd. (Pine Cliff). All services performed were charged at estimated fair value. As at June 30, 2019, the Company had an account receivable from Pine Cliff of $32,000 (December 31, 2018 – $71,000).

5. SUBORDINATED PROMISSORY NOTE

As at June 30, 2019, Bonterra had $7,500,000 (December 31, 2018 - $10,000,000) 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 first six months was $186,000 (June 30, 2018 - $262,000). 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.

6. BANK DEBT

As at June 30, 2019, the Company has a bank facility of $340,000,000 (December 31, 2018 - $380,000,000), comprised of a $300,000,000 syndicated revolving credit facility and a $40,000,000 non-syndicated revolving credit facility. The amount drawn under the total bank facility of $340,000,000 at June 30, 2019 was $288,545,000 (December 31, 2018 - $298,660,000). The amounts borrowed under the bank facility bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 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 28, 2020, with a maturity date of April 29, 2021, subject to annual review. The credit facilities have no fixed terms of repayment. Also, the Company has an accordion feature which allows it to obtain future funding of up to $40,000,000 for opportunities outside of normal operations, such as acquisitions, subject to unanimous lender approval.

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.

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 June 30, 2019 (December 31, 2018 - $900,000). Security for the bank facility consists of various floating demand debentures totaling $750,000,000 (December 31, 2018 - $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 $340,000,000 in consolidated debt (excluding accounts payable and accrued liabilities). As at June 30, 2019 consolidated debt is $ 308,045,000
- 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 five 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. As at June 30, 2019, the Company is in compliance with all covenants.

7. INCOME TAXES

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

	Three Months		Six Months	
($ 000s)	**June 30, 2019**	June 30, 2018	**June 30, 2019**	June 30, 2018
Earnings (loss) before taxes	**3,787**	12,493	**5,867**	17,557
Combined federal and provincial income tax rates	**27.00%**	27.00%	**27.00%**	27.00%
Income tax provision calculated using statutory tax rates	**1,022**	3,373	**1,584**	4,740
Increase (decrease) in taxes resulting from:				
Change in statutory tax rates [1]	**(19,035)**	-	**(18,946)**	-
Share-option compensation	**167**	207	**318**	407
Change in unrecorded benefits of tax pools	**(1,569)**	-	**(1,569)**	-
Change in estimates and other	**71**	(12)	**(108)**	90
	(19,344)	3,568	**(18,721)**	5,237

(1) Effective July 1, 2019 the combined federal and provincial income tax rate for Bonterra is approximately 26.00% due to the provincial tax rate for Alberta, Canada decreasing from 12% to 11%. The provincial tax rate for Alberta will further decrease to 10% on January 1, 2020, 9% on January 1, 2021 and 8% on January 1, 2022.

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	81,600
Share issue costs	20	11
Canadian oil and gas property expenditures	10	89,131
Canadian development expenditures	30	144,788
Canadian exploration expenditures	100	8,587
Federal income tax losses carried forward[1]	100	35,122
		359,239

(1) Federal income tax losses carried forward expire in the following years; 2036 - $34,913,000; 2037 - $209,000.

The Company has $8,861,000 (December 31, 2018 - $8,861,000) of investment tax credits that expire in the following years: 2024 - $1,319,000; 2025 - $2,258,000; 2026 - $2,405,000; 2027- $2,009,000; 2028 - $745,000; 2034 - $99,000; and 2037 - $26,000

The Company has $65,015,000 (December 31, 2018 - $65,015,000) of capital losses carried forward which can only be claimed against taxable capital gains.

8. SHAREHOLDERS' EQUITY

Authorized

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

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

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 six months ended June 30 is as follows:

	Three Months		Six Months	
	June 30, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
Basic shares outstanding	**33,388,796**	33,310,796	**33,388,796**	33,310,796
Dilutive effect of share options [1]	**-**	25,428	**-**	-
Diluted shares outstanding	**33,388,796**	33,336,224	**33,388,796**	33,310,796

[1] The Company did not include 2,760,000 share-options for the three months ended June 30, 2019 (June 30, 2018 – 1,831,000) and 2,760,000 share options for the six months ended June 30, 2019 (June 30, 2018 – 2,693,000) in the dilutive effect of share-options calculations as these share-options were anti-dilutive.

For the three months ended June 30, 2019, the Company declared and paid dividends of $1,002,000 ($0.03 per share) (June 30, 2018 - $9,993,000 ($0.30 per share)). For the six months ended June 30, 2019, the Company declared and paid dividends of $2,003,000 ($0.06 per share) (June 30, 2018 - $19,986,000 ($0.60 per share)).

The Company provides an equity settled 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 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 June 30, 2019 and changes during the year ended are presented below:

	Number of options	**Weighted average exercise price**
At December 31, 2018	2,794,000	$11.62
Options granted	60,000	5.79
Options forfeited	(78,000)	11.24
Options expired	(16,000)	27.95
At June 30, 2019	2,760,000	$11.40

The following table summarizes information about options outstanding and exercisable as at June 30, 2019:

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable	Weighted-average exercise price
$ 5.00 - $ 10.00	1,061,000	1.7 years	$ 5.92	-	$ -
10.01 - 15.00	1,583,000	0.8 years	14.56	753,000	14.56
15.01 - 25.00	116,000	1.3 years	18.56	38,000	18.57
$ 5.00 - $ 25.00	2,760,000	1.2 years	$ 11.40	791,000	$ 14.75

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 directors, officers and employees. During the six months ended June 30, 2019, the Company granted 60,000 options with an estimated fair value of $86,000 or $1.43 per option using the Black-Scholes option pricing model with the following key assumptions:

	June 30, 2019
Weighted-average risk free interest rate (%)[1]	**1.62**
Weighted-average expected life (years)	**2.0**
Weighted-average volatility (%)[2]	**49.06**
Forfeiture rate (%)	**7.37**
Weighted average dividend yield (%)	**2.05**

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for one, two, and three year terms to match corresponding vesting periods.
(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

9. OIL AND GAS SALES, NET OF ROYALTIES

	Three months		Six months	
($ 000s)	**June 30, 2019**	June 30, 2018	**June 30, 2019**	June 30, 2018
Oil and gas sales				
Crude oil	**50,235**	60,869	**91,578**	109,879
Natural gas liquids	**2,253**	3,912	**4,935**	7,047
Natural gas	**2,364**	2,677	**8,173**	7,657
	54,852	67,458	**104,686**	124,583
Less royalties:				
Crown	**(1,683)**	(4,090)	**(3,887)**	(7,897)
Freehold, gross overriding royalties and other	**(1,832)**	(2,820)	**(3,642)**	(4,795)
	(3,515)	(6,910)	**(7,529)**	(12,692)
Oil and gas sales, net of royalties	**51,337**	60,548	**97,157**	111,891

10. FINANCIAL RISK MANAGEMENT

The Company is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. 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. Bonterra's exposure to credit risk, liquidity risk and market risk are consistent with those discussed in Note 20 of the Company's audited annual financial statements for the year ended December 31, 2018.

Physical Delivery Sales Contracts

Bonterra enters into physical delivery sales contracts to manage commodity price risk. These contracts are considered normal executory sales contracts and are not recorded at fair value in the financial statements. As of June 30, 2019, the Company has the following physical delivery sales contract in place.

Product	Type of contract	Volume	Term	Contract price
Oil	Fixed price - MSW Stream index[1]	1,000 BBL/day	May 1 to Sept 30, 2019	$77.35 CAD/BBL

Subsequent to June 30, 2019, the Company entered into the following physical delivery sales contract.

Product	Type of contract	Volume	Term	Contract price
Oil	Fixed price - MSW Stream index[1]	1,000 BBL/day	Sept 1 to Dec 31, 2019	$67.75 CAD/BBL

(1) "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.

Risk Management Contract

On July 31, 2019, the Company also entered into a financial derivative for the period October 1, 2019 to December 31, 2019 for a total of 46,000 barrels of oil (approximately 500 barrels of oil per day) at a fixed MSW stream index price of $65.00 CAD per barrel.

11. SUBSEQUENT EVENTS

Dividends

Subsequent to June 30, 2019, the Company declared the following dividends:

Date declared	Record date	$ per share	Date payable
July 2, 2019	July 15, 2019	0.01	July 31, 2019
August 1, 2019	August 15, 2019	0.01	August 30, 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

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