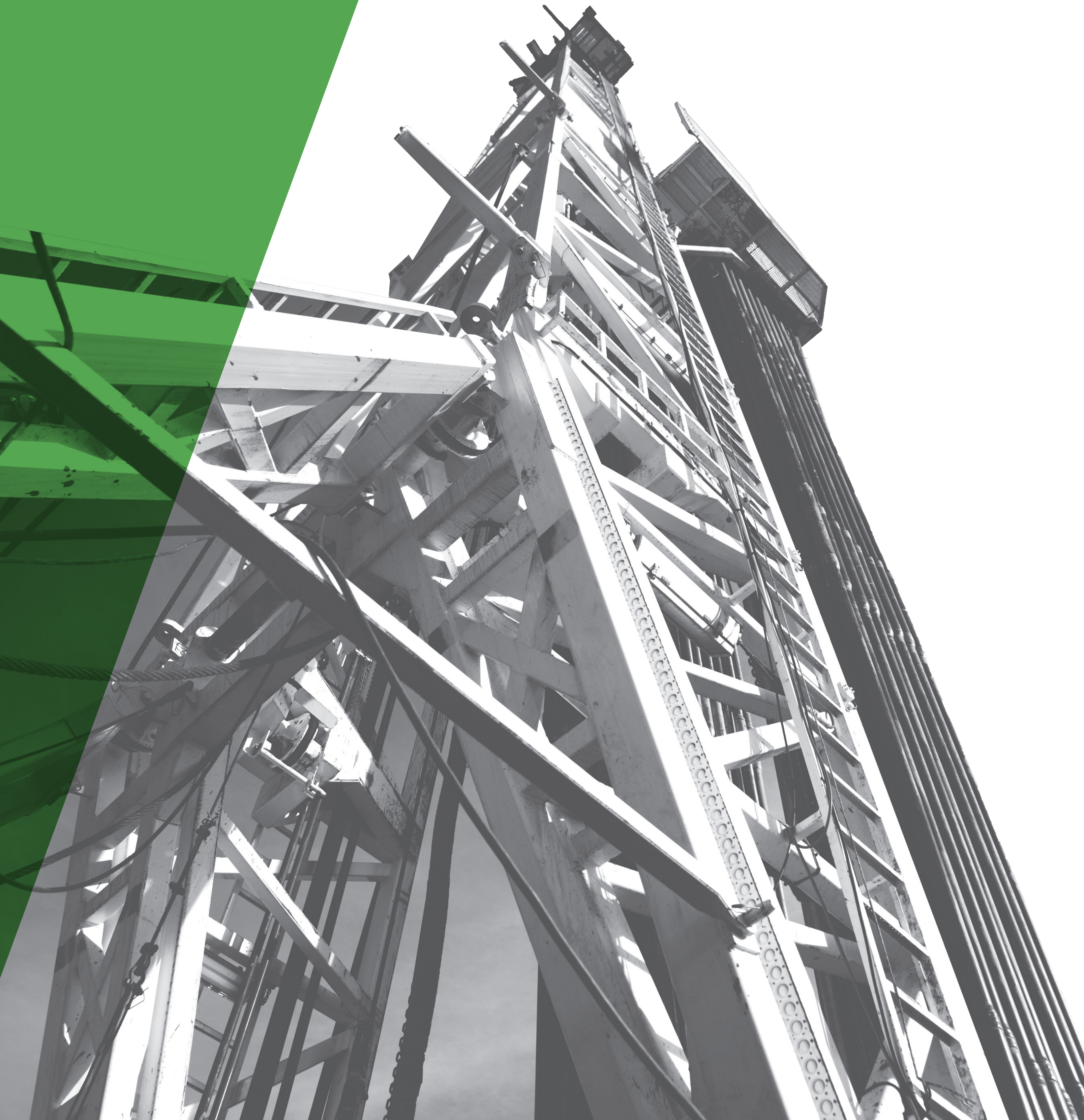
Bonterra Energy Corp.

2019 ANNUAL REPORT



Bonterra Energy Corp. is a conventional oil and gas company with an asset base comprised of concentrated, stable and underdeveloped properties located across western Canada, and is a leading operator in the light oil Pembina Cardium reservoir. With a proven track record of delivering per share growth and creating long-term value for shareholders, the Company's strategy for success is based on sustainable operations, an experienced management team, premium assets and a commitment to maintaining a prudent capital structure.

TABLE OF CONTENTS

$36.1 MILLION

Reduction of Net Debt Year-Over-Year

$2.88 PER SHARE

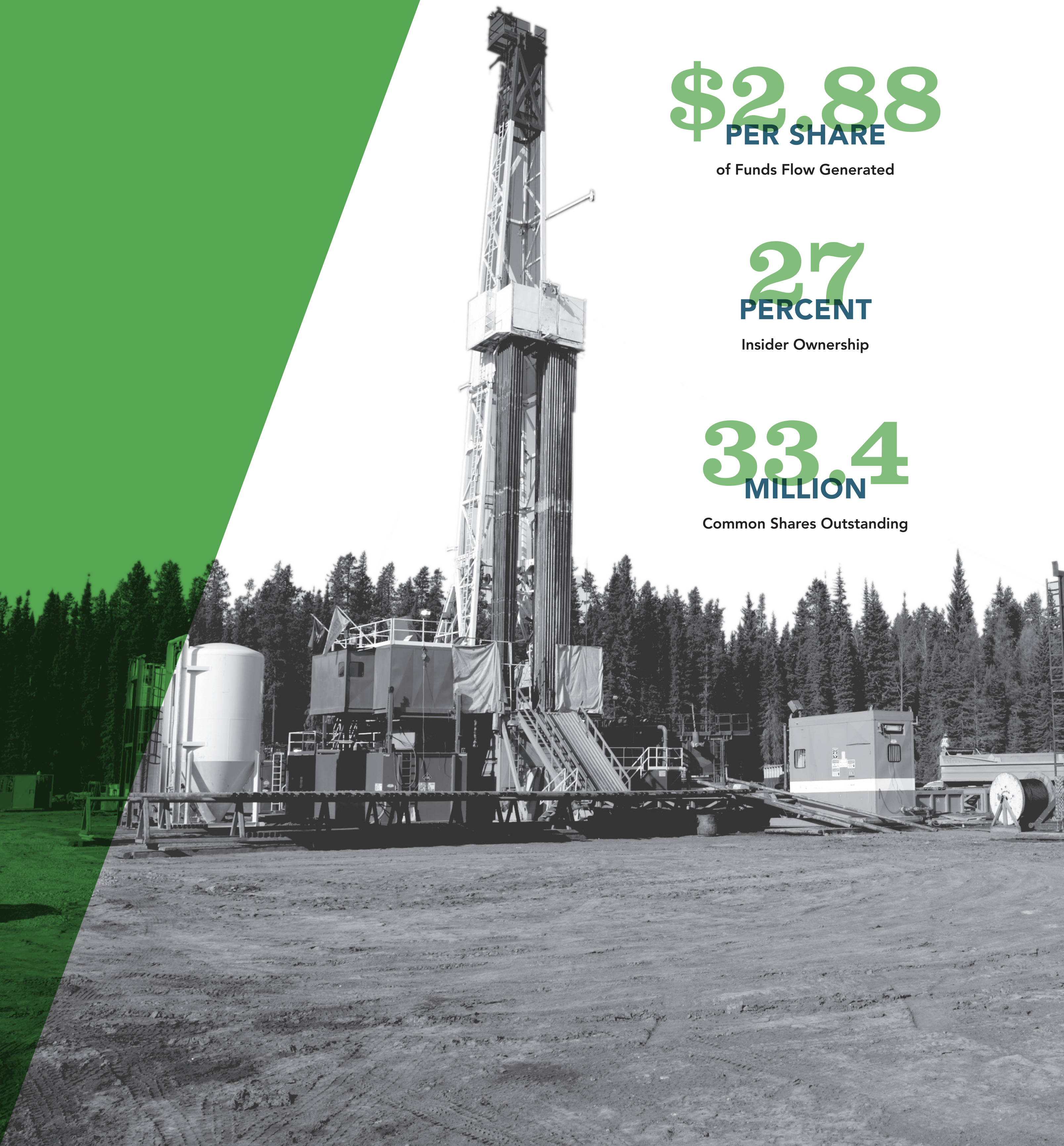
of Funds Flow Generated

27 PERCENT

Insider Ownership

33.4 MILLION

Common Shares Outstanding



Bonterra's ADVANTAGE

Bonterra's assets are concentrated in Alberta's Pembina and Willesden Green Cardium fields, among Canada's largest oil reservoirs, and are characterized by **low-risk drilling opportunities, stable production rates and high-quality light oil**. We are dedicated to reducing debt and creating **sustainable value for our shareholders** by generating Free Funds Flow. Our low corporate decline rate of 21 percent requires minimal capital to sustain production, supporting **financial flexibility** through a volatile commodity price environment.

$96.3 MILLION

Funds Flow Generated in 2019[1]

The Company generated significant Funds Flow in 2019, allowing for a fully funded capital program, payment of a monthly dividend, and the creation of $36.1 million in Free Funds Flow[2].

67 PERCENT

Oil and Liquids Weighting

An oil-weighted, low-risk and long-life asset base, coupled with a low decline rate that averaged 21 percent in 2019, supports long-term sustainability.

$53.6 MILLION

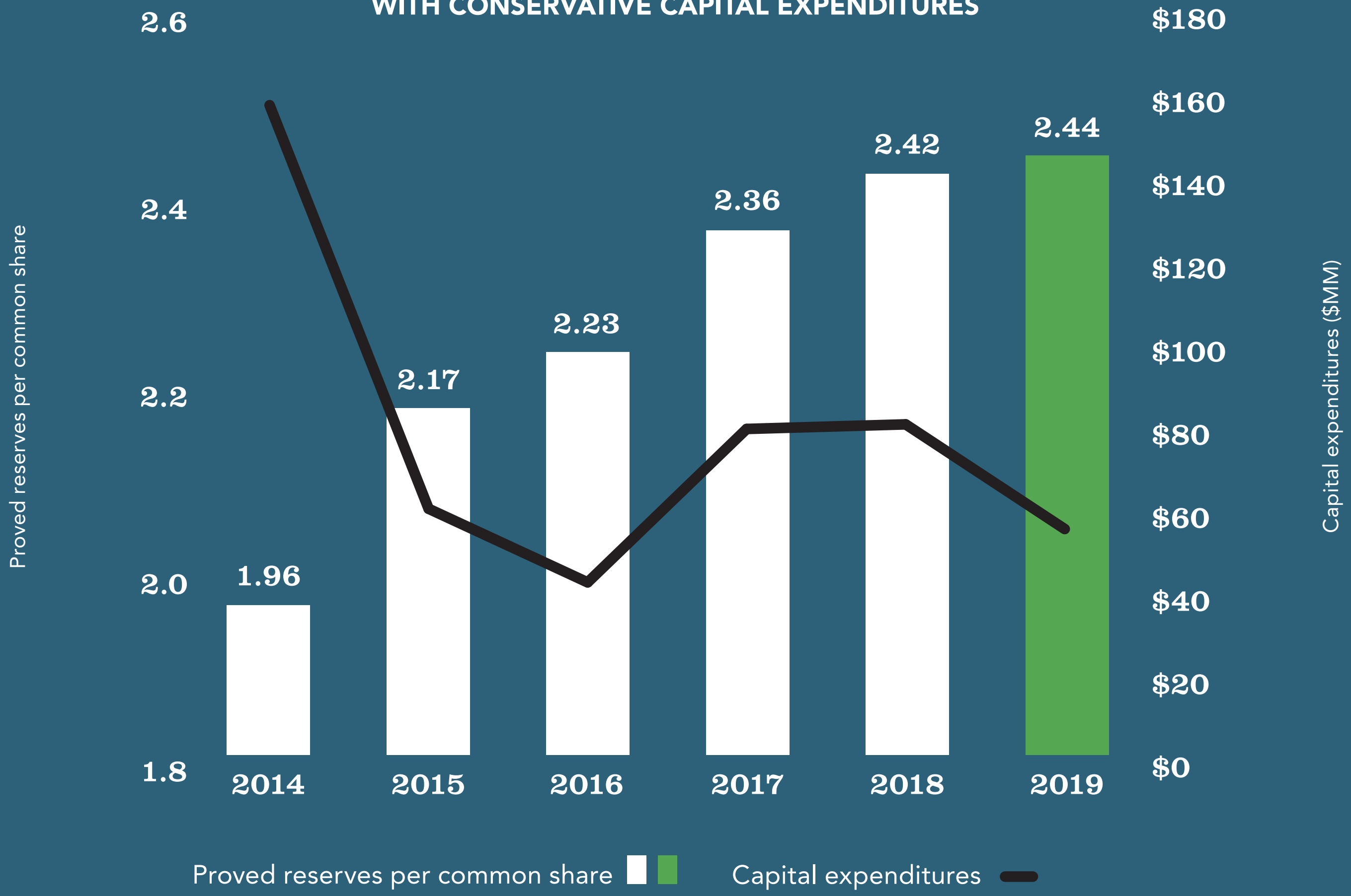
Capital Invested in 2019

Bonterra directed $44.5 million to drill 30 gross (23.7 net) new wells, complete and tie-in 27 gross (20.7 net) wells and allocated approximately $9.1 million towards infrastructure investments.

(1) Funds Flow is defined as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

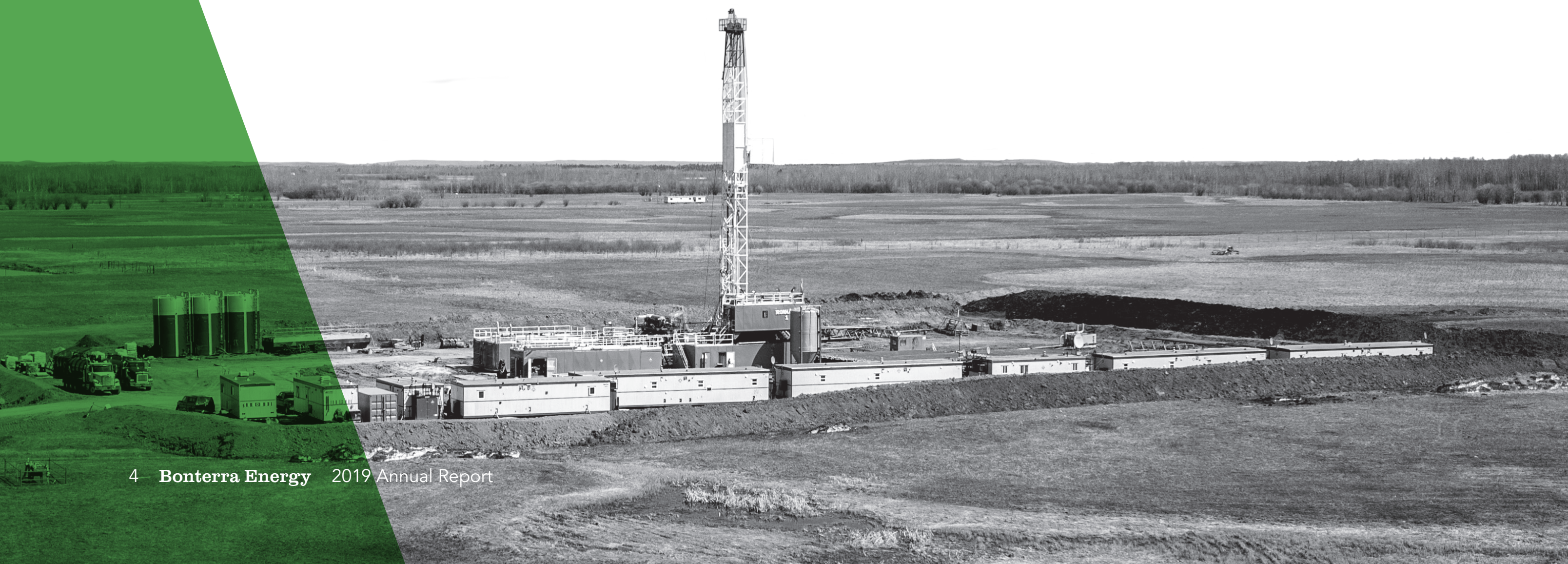
(2) Free Funds Flow is defined as Funds Flow less dividends paid to shareholders, capital and decommissioning expenditures settled.

GROWING PROVED RESERVES PER SHARE WITH CONSERVATIVE CAPITAL EXPENDITURES

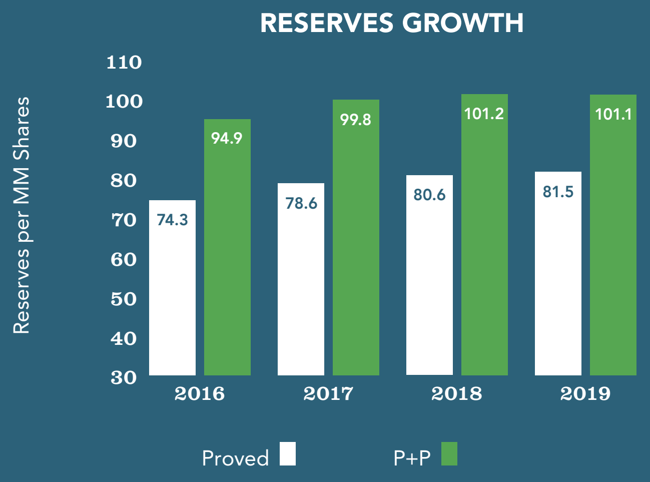


2019 HIGHLIGHTS

During 2019, Bonterra's conservative capital expenditures reflected commodity price volatility and our net debt reduction focus. With a **$53.6 million capital program**, average daily production remained stable at **12,305 BOE** per day. Funds Flow totaled **$96.3 million**, and **$36.1 million of Free Funds Flow** was directed to reducing net debt by **11 percent** year-over-year. **Dividends to shareholders totaled $4.0 million**, achieving a capital plus dividend **payout ratio of 60 percent**, demonstrating Bonterra's commitment to generating returns for shareholders across various commodity price environments.



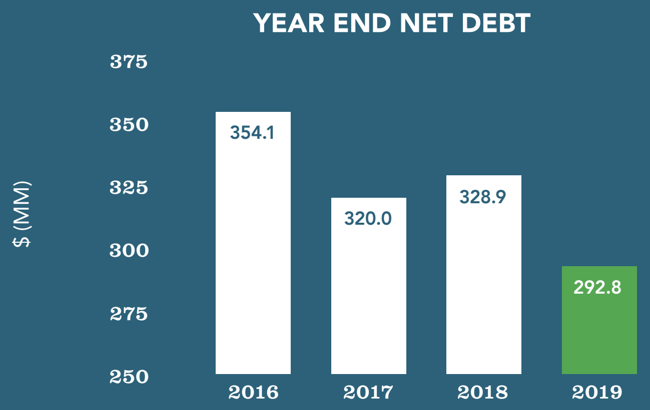
Bonterra's focus will remain on generating strong, sustainable Free Funds Flow which can be used to further reduce debt over the shorter term, pursue growth opportunities or pay dividends as the balance sheet strengthens over the longer term.



10 PERCENT

Increase in Proved Reserves from 2016 to 2019

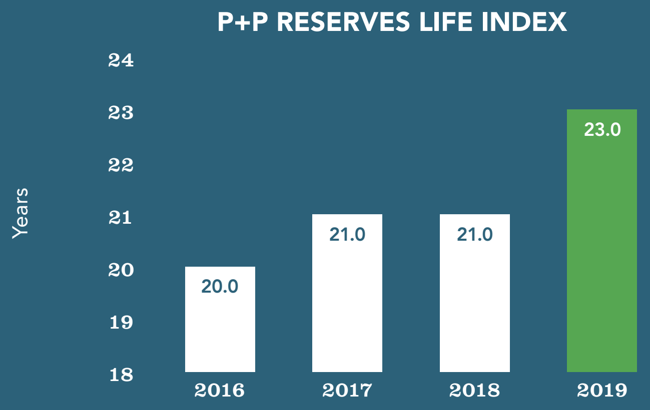
Bonterra's continued ability to generate long-term value and to bolster its asset base is reflected in the 10 percent increase in proved reserves, and the seven percent increase in proved plus probable ("P+P") reserves since 2016.



11 PERCENT

Decrease in Net Debt 2019 vs 2018

Bonterra continues to focus on monitoring overall net debt while managing Funds Flow and capital expenditures. The Company intends to further reduce net debt levels, strengthen the balance sheet and enhance financial flexibility.



23 YEARS

2019 Reserve Life Index

Bonterra's reserve life index, calculated as the P+P reserves divided by annualized production, increased 10 percent to 23 years in 2019 compared to 21 years in 2018, providing an extended runway for future development.

Annual HIGHLIGHTS

As at and for the year ended ($ 000s except $ per share)		December 31, 2019	December 31, 2018	December 31, 2017
FINANCIAL				
Revenue – realized oil and gas sales		**202,749**	223,388	202,566
Funds Flow[(1)]		**96,261**	107,251	102,444
Per share – basic and diluted		**2.88**	3.22	3.08
Dividend payout ratio		**4%**	34%	39%
Cash flow from operations		**81,132**	115,963	103,873
Per share – basic and diluted		**2.43**	3.48	3.12
Dividend payout ratio		**5%**	32%	38%
Cash dividends per share		**0.12**	1.11	1.20
Net earnings		**21,923**	7,167	2,506
Per share – basic and diluted		**0.66**	0.22	0.08
Capital expenditures		**53,627**	78,737	82,441
Disposition		**-**	-	56,752[(2)]
Total assets		**1,087,817**	1,103,833	1,125,551
Working capital deficiency		**19,745**	30,281	27,790
Long-term debt		**273,065**	298,660	292,212
Shareholders' equity		**503,949**	483,970	510,260
OPERATIONS				
Oil	– bbl per day	**7,310**	8,119	7,907
	– average price ($ per bbl)	**66.34**	65.51	59.30
NGLs	– bbl per day	**986**	995	905
	– average price ($ per bbl)	**25.83**	40.32	31.47
Natural gas	– MCF per day	**24,053**	24,549	24,087
	– average price ($ per MCF)	**1.87**	1.63	2.40
Total barrels of oil equivalent per day (BOE)[(3)]		**12,305**	13,206	12,827

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

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

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

Quarterly HIGHLIGHTS

	2019			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
FINANCIAL				
Revenue – oil and gas sales	**50,743**	47,320	54,852	49,834
Funds Flow[(1)]	**23,055**	22,596	26,247	24,363
Per share – basic and diluted	**0.69**	0.68	0.79	0.73
Dividend payout ratio	**4%**	4%	4%	4%
Cash flow from operations	**20,767**	19,774	25,468	15,123
Per share – basic and diluted	**0.62**	0.59	0.76	0.45
Dividend payout ratio	**5%**	5%	4%	7%
Cash dividends per share	**0.03**	0.03	0.03	0.03
Net earnings (loss)	**(1,389)**	(1,276)	23,131	1,457
Per share – basic and diluted	**(0.04)**	(0.04)	0.69	0.04
Capital expenditures	**5,678**	17,845	9,042	21,062
Total assets	**1,087,817**	1,133,137	1,123,513	1,124,043
Working capital deficiency	**19,745**	24,599	22,238	30,139
Long-term debt	**273,065**	283,470	288,545	296,594
Shareholders' equity	**503,949**	506,011	507,659	484,980
OPERATIONS				
Oil (barrels per day)	**7,255**	7,157	7,746	7,081
Average price ($ per bbl)	**63.37**	65.49	71.27	64.87
NGLs (barrels per day)	**1,016**	1,009	970	949
Average price ($ per bbl)	**24.39**	22.45	25.53	31.40
Natural gas (MCF per day)	**24,697**	23,820	23,750	23,938
Average price ($ per MCF)	**2.71**	0.96	1.09	2.70
Total BOE per day[(2)]	**12,387**	12,136	12,674	12,020

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(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") has faced unprecedented challenges impacting the Canadian energy industry through 2019 and into 2020 including extreme commodity price volatility, global oil supply and demand imbalances caused by price wars, pipeline capacity constraints, adjustments to regulatory policy and the recent impact of COVID-19 (Coronavirus) which have combined to create an increasingly difficult environment for oil and gas producers. This backdrop highlights the importance of Bonterra's commitment to maintaining or reducing debt levels, executing a defensive capital program and seeking to conservatively manage its assets to support long-term shareholder value creation.

Bonterra 2019 Highlights

- Averaged 12,305 BOE per day of production in 2019 and 12,387 BOE per day for the final three months of the year, reflecting modest capital spending in 2019 coupled with approximately 350 BOE per day of shut-in production volumes related to facility maintenance and low natural gas prices.
- Generated Funds Flow of $96.3 million ($2.88 per share) in 2019 which supported continued funding of Bonterra's capital program, monthly dividend and debt repayment.
- Invested approximately $53.6 million in capital expenditures for the year ended December 31, 2019, with $44.5 million directed to drilling 30 gross (23.7 net) wells with a 100 percent success rate, and completing and tying in 27 gross (20.7 net) wells, with the remaining three gross (3.0 net) wells commencing production in early Q1 2020; the additional $9.1 million was directed to infrastructure investments.
- Reduced net debt by 11 percent to $292.8 million compared to $328.9 million at December 31, 2018, improving Bonterra's financial flexibility and enhancing long-term sustainability.
- Recorded Free Funds Flow of $36.1 million which was allocated to meaningful reductions in net debt.
- Total proved reserves per fully diluted share totaled 2.44 BOE, a 1.0 percent increase over 2.42 BOE in 2018, while P+P reserves per fully diluted share totaled 3.03 BOE compared to 3.04 BOE per share in 2018.

Bonterra's Advantages

Bonterra continues to focus on the prudent development of our high-quality, light sweet oil-weighted asset base, and to take a conservative approach to capital allocation, allowing for flexibility in response to extreme variability of global commodity markets. Balance sheet strength and the protection of value in this environment remain top priorities in the near term, with an ongoing focus on responding strategically to commodity price instability.

Cost control has always been a hallmark of Bonterra's operations, and this focus will continue through 2020 and beyond. By owning the majority of its facilities and gas plants, Bonterra can maintain better control of its cost structure through the processing of its oil, natural gas liquids and natural gas. Bonterra operates 90 percent of its production with an average working interest of 76 percent and operates most of the related oil and gas processing facilities, which require minimal additional capital to increase throughput. At approximately 21 percent, the Company has one of the lowest decline rates among its peer group, which contributes to low maintenance capital requirements and supports long-term sustainability.

Outlook

The global events mentioned above have reinforced the importance of maintaining an adaptable capital strategy and taking a defensive position to protect the organization amidst severe uncertainty. Consistent with this strategy, the Company has taken several steps to ensure strength and resiliency during this period. Bonterra has committed to spending capital of approximately $25 million and will defer any additional drilling or completions capital investment until pricing is more supportive. Further, the Company has actively assessed areas and infrastructure that are uneconomic in the current environment and has shut-in production volumes to protect corporate returns. Lastly, the Company's Board of Directors elected to suspend its monthly dividend, commencing in April, until the economic environment can support a sustained dividend payment. Along with our commitment to Environmental, Social, and Governance principles, Bonterra's strategy is designed to withstand volatile commodity prices and a highly uncertain outlook.

To further mitigate the continued commodity price volatility and support added stability, the Company has entered into physical delivery sales and risk management contracts to realize average Edmonton Par prices on crude oil between C$59.08 and C$69.60 per bbl on 2,000 barrels per day of production for January to February, 2,500 barrels per day for March and 2,000 barrels per day for the second quarter of 2020. The Company will continue to pursue additional opportunities to enhance funds flow and financial flexibility.

The Board of directors and management of the Company wish to thank all shareholders for their continued trust through a notably difficult operating environment, and to all employees and consultants for their invaluable contributions.

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

Commitment TO RESPONSIBILITY

Bonterra recognizes the important role we play as an employer, corporate citizen and participant in the local community. We hold ourselves to the highest standards of corporate responsibility, and approach business in a way that fosters responsible oil and gas development.

Bonterra recognizes that corporate responsibility does not end at the operational level; in reality, it extends to our community and beyond. As a Company, community means more than just the location in which we conduct business.

We endeavour to support the individuals, groups, and municipalities in and around the locations where we operate through equal opportunity and we prioritize the employment of local businesses and community members to conduct our operations.

Health, Safety and Environment (HS&E)

Bonterra is committed to meet or exceed all relevant industry HS&E regulations and standards. We accomplish our HS&E goals by implementing a program, applicable to all of Bonterra's operations and employees, that considers a broad range of stakeholders and workplace environments. Our HS&E practices underscore the following priorities:

- Employing minimal disturbance techniques to reduce the overall impact to the environment caused by our operations;
- Ensure all employees, contractors, and Company representatives are provided with applicable health, safety, security and environmental and regulatory training;
- Secure a safe work environment with robust policies, procedures, equipment and emergency response plans;
- Provide timely and effective response to any incidents that may occur, enabling rapid recoveries and conducting thorough incident investigations;
- Employ vigorous asset integrity programs to ensure the safe operation of pipelines and associated facilities; and
- Consult internal and external stakeholders that are impacted by our operations, and remain committed to working with involved parties to resolve any concerns or questions that may arise.

Photo by Jasper Gronewold on Unsplash

Statistical REVIEW

Summary of Gross Oil and Gas Reserves as of December 31, 2019

Reserves Category	Light & Medium Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[4] (MBoe)	Future Development Capital ($ 000s)
PROVED					
Developed Producing	22,227	75,544	3,319	38,136	76
Developed Non-producing	591	1,219	55	849	1,374
Undeveloped	23,891	85,582	4,398	42,552	638,193
TOTAL PROVED	46,709	162,345	7,771	81,537	639,643
PROBABLE	11,165	38,981	1,878	19,540	12,006
TOTAL PROVED PLUS PROBABLE[1][2][3]	57,874	201,326	9,649	101,077	651,650

(1) Reserves have been presented on gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company.

(2) Totals may not add due to rounding.

(3) Based on Sproule's December 31, 2019 escalated price deck.

(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Reconciliation of Company Gross Reserves by Principal Product Type as of December 31, 2019[1][2]

	Light & Medium Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total	
	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable
	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(MBoe)	(MBoe)
Opening Balance, December 31, 2018	47,885	60,067	153,973	193,380	7,086	8,928	80,634	101,225
Extensions & Improved Recovery[2]	2,551	3,154	9,348	11,543	664	817	4,773	5,894
Technical Revisions	(375)	(2,034)	8,517	5,825	481	365	1,525	(698)
Discoveries	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-
Dispositions[3]	-	-	-	-	-	-	-	-
Economic Factors	(685)	(645)	(714)	(643)	(100)	(101)	(904)	(853)
Production	(2,668)	(2,668)	(8,779)	(8,779)	(360)	(360)	(4,491)	(4,491)
CLOSING BALANCE, DECEMBER 31, 2019[4]	**46,709**	**57,874**	**162,345**	**201,326**	**7,771**	**9,649**	**81,537**	**101,077**

(1) Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) Increases to Extensions & Improved Recovery include infill drilling and are the result of step-out locations drilled by Bonterra and other operators on and near Company-owned lands.

(3) Includes volumes associated with Farm outs.

(4) Totals may not add due to rounding.

Summary of Net Present Values of Future Net Revenue as of December 31, 2019

($ 000s)	Net Present Value Before Income Taxes Discounted at (% per Year)			
Reserves Category	0%	5%	10%	15%
PROVED				
Developed Producing	789,954	727,746	586,445	485,957
Developed Non-producing	17,432	13,466	10,627	8,593
Undeveloped	981,038	578,193	364,808	241,291
TOTAL PROVED	1,788,424	1,319,405	961,880	735,842
PROBABLE	731,254	402,609	266,354	196,077
TOTAL PROVED + PROBABLE(1)(2)(3)(4)	2,519,678	1,722,014	1,228,235	931,919

(1) Evaluated by Sproule as at December 31, 2019. Net present value of future net revenue does not represent fair value of the reserves.

(2) Net present values equal net present value before income taxes based on Sproule's forecast prices and costs as of December 31, 2019. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material.

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

(4) Total may not add due to rounding.

Finding, Development & Acquisition (FD&A) and Finding & Development (F&D) Costs

	Proved Reserves Net Additions				Proved + Probable Reserves Net Additions			
	2019	2018	2017	3 Yr Avg(4)	2019	2018	2017	3 Yr Avg(4)
FD&A COSTS PER BOE(1)(2)(3)								
Including FDC	$ 14.32	$ 12.82	$ 15.66	$ 14.41	$ 18.24	$ 14.33	$ 13.74	$ 14.89
Excluding FDC	$ 9.94	$ 11.40	$ 9.06	$ 10.04	$ 12.35	$ 12.70	$ 8.57	$ 10.65
F&D COSTS PER BOE(1)(2)(3)								
Including FDC	$ 14.32	$ 12.99	$ 16.93	$ 14.98	$ 18.24	$ 15.56	$ 15.13	$ 16.02
Excluding FDC	$ 9.94	$ 12.54	$ 9.46	$ 10.55	$ 12.35	$ 14.95	$ 9.16	$ 11.59

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

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(3) FD&A and F&D costs are net of proceeds of disposal and the FD&A costs per BOE are based on reserves acquired net of reserves disposed of.

(4) Three-year average is calculated using three-year total capital costs and reserve additions on both Proved and Proved + Probable reserves on a weighted average basis.

Commodity Prices Used in the Above Calculations of Reserves are as Follows:

Year	Edmonton Par Price ($Cdn per bbl)	Natural Gas AECO-C Spot ($Cdn per Mmbtu)	Butanes Edmonton ($Cdn per bbl)	Pentanes Edmonton ($Cdn per bbl)	Operating Cost Inflation Rate (% per Year)	Exchange Rate ($US/$Cdn)
FORECAST						
2020	73.84	2.04	37.72	76.32	0.0	0.76
2021	78.51	2.27	43.90	80.52	1.0	0.77
2022	78.73	2.81	47.74	80.00	2.0	0.80
2023	80.30	2.89	48.69	81.68	2.0	0.80
2024	81.91	2.98	49.67	83.38	2.0	0.80
2025	83.54	3.06	50.66	85.13	2.0	0.80
2026	85.21	3.15	51.67	86.90	2.0	0.80
2027	86.92	3.24	52.71	88.72	2.0	0.80
2028	88.66	3.33	53.76	90.57	2.0	0.80
2029	90.43	3.42	54.84	92.45	2.0	0.80
2030	92.24	3.51	55.93	94.38	2.0	0.80

Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.

Production

	2019		
	Oil & NGLs (bbl per day)	**Conventional Natural Gas (MCF per day)**	**Total (BOE per day)**
Alberta	**8,155**	**23,227**	**12,026**
Saskatchewan	**136**	**40**	**143**
British Columbia	**5**	**786**	**136**
	8,296	**24,053**	**12,305**

Land Holdings

	2019		2018	
	Gross Acres	**Net Acres**	Gross Acres	Net Acres
Alberta	**331,566**	**203,191**	339,019	208,086
Saskatchewan	**8,637**	**5,680**	8,178	5,691
British Columbia	**62,045**	**23,690**	62,045	23,478
	402,248	**232,561**	409,242	237,255

Petroleum and Natural Gas Expenditures

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

($ 000s)	**2019**	2018
Land	**-**	535
Acquisitions	**-**	3,125
Disposals	**-**	-
Exploration and development costs	**53,627**	75,077
Net petroleum and natural gas capital expenditures	**53,627**	78,737

Drilling History

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

	2019					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil	**30.0**	**23.7**	**-**	**-**	**30.0**	**23.7**
Natural gas	**-**	**-**	**-**	**-**	**-**	**-**
Total	**30.0**	**23.7**	**-**	**-**	**30.0**	**23.7**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	2018					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	34.0	28.0	-	-	34.0	28.0
Natural gas	-	-	-	-	-	-
Total	34.0	28.0	-	-	34.0	28.0
Success rate	100%	100%	-	-	100%	100%

Management's Discussion and Analysis

The following report dated March 10, 2020 is a review of the operations and current financial position for the year ended December 31, 2019 for Bonterra Energy Corp. ("Bonterra" or "the Company") and should be read in conjunction with the audited financial statements presented under International Financial Reporting Standards (IFRS), including the notes related thereto.

Use of Non-IFRS Financial Measures

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio", "cash netback" and "net debt" to analyze operating performance, which are not standardized measures recognized under IFRS and do not have a standardized meaning prescribed by IFRS. These measures are commonly used in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies.

The Company calculates payout ratio percentage by dividing cash dividends paid to shareholders by cash flow from operating activities, both of which are measures prescribed by IFRS which appear on our statement of cash flows. We calculate cash netback by dividing various financial statement items as determined by IFRS by total production for the period on a barrel of oil equivalent basis. The Company calculates net debt as long-term debt plus working capital deficiency (current liabilities less current assets).

Frequently Recurring Terms

Bonterra uses the following frequently recurring terms in this MD&A: "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States; "MSW Stream Index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada; "AECO" refers to Alberta Energy Company, a grade or heating content of natural gas used as benchmark pricing in Alberta, Canada; "bbl" refers to barrel; "NGL" refers to Natural gas liquids; "MCF" refers to thousand cubic feet; "MMBTU" refers to million British Thermal Units; "GJ" refers to gigajoule; and "BOE" refers to barrels of oil equivalent. Disclosure provided herein in respect of a BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Numerical Amounts

The reporting and the functional currency of the Company is the Canadian dollar.

2019 Annual Report Bonterra Energy 15

Annual Comparisons

As at and for the year ended ($ 000s except $ per share)		**December 31, 2019**	December 31, 2018	December 31, 2017
FINANCIAL				
Revenue – realized oil and gas sales		**202,749**	223,388	202,566
Cash flow from operations		**81,132**	115,963	103,873
Per share – basic and diluted		**2.43**	3.48	3.12
Payout ratio		**5%**	32%	38%
Cash dividends per share		**0.12**	1.11	1.20
Net earnings		**21,923**	7,167	2,506
Per share – basic and diluted		**0.66**	0.22	0.08
Capital expenditures, net of disposition		**53,627**	78,737	82,441
Disposition		**-**	-	56,752[(1)]
Total assets		**1,087,817**	1,103,833	1,125,551
Working capital deficiency		**19,745**	30,281	27,790
Long-term debt		**273,065**	298,660	292,212
Shareholders' equity		**503,949**	483,970	510,260
OPERATIONS				
Oil	– bbl per day	**7,310**	8,119	7,907
	– average price ($ per bbl)	**66.34**	65.51	59.30
NGLs	– bbl per day	**986**	995	905
	– average price ($ per bbl)	**25.83**	40.32	31.47
Natural gas	– MCF per day	**24,053**	24,549	24,087
	– average price ($ per MCF)	**1.87**	1.63	2.40
Total barrels of oil equivalent per day (BOE)		**12,305**	13,206	12,827

(1) For Q4 2017, includes the disposition of a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool that closed December 20, 2017 and 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).

2019 Annual Report Bonterra Energy 16

Quarterly Comparisons

	2019			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
FINANCIAL				
Revenue – oil and gas sales	**50,743**	47,320	54,852	49,834
Cash flow from operations	**20,767**	19,774	25,468	15,123
Per share – basic and diluted	**0.62**	0.59	0.76	0.45
Dividend payout ratio	**5%**	5%	4%	7%
Cash dividends per share	**0.03**	0.03	0.03	0.03
Net earnings (loss)	**(1,389)**	(1,276)	23,131	1,457
Per share – basic and diluted	**(0.04)**	(0.04)	0.69	0.04
Capital expenditures	**5,678**	17,845	9,042	21,062
Total assets	**1,087,817**	1,133,137	1,123,513	1,124,043
Working capital deficiency	**19,745**	24,599	22,238	30,139
Long-term debt	**273,065**	283,470	288,545	296,594
Shareholders' equity	**503,949**	506,011	507,659	484,980
OPERATIONS				
Oil (bbl per day)	**7,255**	7,157	7,746	7,081
NGLs (bbl per day)	**1,016**	1,009	970	949
Natural gas (MCF per day)	**24,697**	23,820	23,750	23,938
Total BOE per day	**12,387**	12,136	12,674	12,020

	2018			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
FINANCIAL				
Revenue – oil and gas sales	34,988	63,817	67,458	57,124
Cash flow from operations	20,509	33,669	31,908	29,877
Per share – basic and diluted	0.61	1.01	0.96	0.90
Dividend payout ratio	34%	30%	31%	33%
Cash dividends per share	0.21	0.30	0.30	0.30
Net earnings (loss)	(10,909)	5,756	8,925	3,395
Per share – basic and diluted	(0.33)	0.17	0.27	0.10
Capital expenditures	4,785	18,814	18,970	36,168
Total assets	1,103,833	1,137,748	1,147,501	1,142,670
Working capital deficiency	30,281	35,319	27,069	46,630
Long-term debt	298,660	293,197	303,413	291,994
Shareholders' equity	483,970	500,507	503,979	504,240
OPERATIONS				
Oil (bbl per day)	7,756	7,949	8,743	8,034
NGLs (bbl per day)	1,025	1,070	984	900
Natural gas (MCF per day)	24,045	24,144	25,317	24,701
Total BOE per day	12,789	13,043	13,946	13,051

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 in 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.

	Q4-2019	Q3-2019	Q2-2019	Q1-2019	Q4-2018	Q3-2018	Q2-2018	Q1-2018
Crude oil WTI (US$/bbl)	**56.96**	56.45	59.81	54.90	58.81	69.50	67.88	62.87
WTI to MSW Stream Index Differential (US$/bbl)[1]	**(5.37)**	(4.66)	(4.62)	(4.85)	(26.30)	(6.83)	(5.45)	(5.89)
Foreign exchange US$ to Cdn$	**1.3201**	1.3207	1.3375	1.3293	1.3215	1.3070	1.2911	1.2651
Bonterra average realized oil price (Cdn$/bbl)	**63.37**	65.49	71.27	64.87	38.96	77.20	76.51	67.78
Natural gas AECO (Cdn$/mcf)	**2.46**	0.91	1.03	2.61	1.55	1.19	1.18	2.07
Bonterra average realized gas price (Cdn$/mcf)	**2.71**	0.96	1.09	2.70	1.77	1.37	1.16	2.24

(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 continued through the fourth quarter of 2019 as uncertainties around global supply and demand persist, along with heightened geopolitical concerns that began earlier in the year with an attack on Saudi Arabia's largest crude processing facility. Concern regarding global demand imbalances in the second half of 2019 and into 2020 comes from a variety of factors, including but not limited to global trade disputes between the US and China and the impact of the Coronavirus epidemic. There is further uncertainty around crude oil supply growth, including continued shale oil development in the US, the impact of which was exacerbated in early March 2020 due to Russia's departure from OPEC+ and Saudi Arabia's stated objective to ramp up production and cause an oil price war. The impact of such competition for market share could have a significant, sustained negative effect on global commodity prices. In Canada, volatility subsided somewhat through 2019 as crude curtailments mandated by the Alberta Government, along with incremental rail and seasonal factors, resulted in a decrease in crude inventories and a narrowing of the differential for all grades of Canadian crude. While the 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.

The AECO benchmark price for natural gas improved into the fourth quarter of 2019 with the onset of winter and the associated increase in heating demand. Looking forward, the implementation of a Temporary Service Protocol to manage supply during maintenance periods on TC Energy's NGTL pipeline system is expected to result in more stable pricing through 2020. Beyond 2020, 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 and 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 ($/bbl)	1.00	2,808	0.08
Realized natural gas price ($/mcf)	0.10	1,016	0.03
U.S.$ to Canadian $ exchange rate	0.01	1,517	0.05

(1) This analysis uses current royalty rates, annualized estimated average production of 12,500 BOE per day and no changes in working capital.

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

Business Overview, Strategy and Key Performance Drivers

Bonterra is an upstream oil and gas company that is primarily focused on the development of its Cardium land within the Pembina and Willesden Green areas located in central Alberta. The Pembina Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original oil in place with very low recoveries to date. Bonterra operates approximately 90 percent of its production and operates the majority of its related oil and gas processing facilities, which require minimal additional capital to support an increase of production. At December 31, 2019, Bonterra has identified a horizontal drilling inventory of approximately 700 net locations (for more information and advisories regarding drilling locations, please refer to Drilling Locations within the Forward Looking Information section). Bonterra has also identified additional drilling locations in other formations within Alberta, Saskatchewan and British Columbia.

Bonterra continues to remain focused on long-term sustainability and improving its balance sheet through debt reduction. During 2019, Bonterra generated cash flow in excess of capital and dividends and reduced net debt by $36.1 million, having closed the year with net debt of $292.8 million, an 11 percent decrease from $328.9 million at December 31, 2018. The Company managed this net debt reduction with reduced capital spending offset by increased production costs from an increased number of required multi-year facility turnarounds in 2019 compared to prior years. With the expected decrease in facility maintenance costs, Bonterra will continue to pursue balance sheet strength and enhanced financial flexibility through 2020. Cash flow after capital and the amount of dividend outlays continues to be prioritized for the enhancement of debt ratios.

During 2019, Bonterra invested $53.6 million in capital, directing approximately $44.5 million to drill 30 gross (23.7 net) wells, complete and tie-in 27 gross (20.7 net) wells, with the remaining three wells brought on production in Q1 2020. In addition, approximately $9.1 million was directed to infrastructure investments, and Bonterra maintained average annual daily production of 12,305 BOE per day. Production was two percent lower than the low end of 2019 guidance disclosed at Q3 2019 of 12,600 BOE per day to 13,200 BOE per day, reflecting approximately 350 BOE per day of production being shut-in through the year related to facility maintenance and low natural gas prices. The Company returned approximately $4 million to shareholders in the form of dividends. Bonterra's all-in payout ratio was 71 percent in 2019, calculated by combining the total dividend amount with capital expenditures and dividing by cash flow from operations.

In response to severe market volatility, and 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 first half of 2020. During 2020, the Company will receive fixed Edmonton Par prices on 2,000 bbls per day of crude oil in Q1 2020 between $64.46 CAD to $69.60 CAD per bbl and on 2,000 bbls per day of crude oil in Q2 2020 between $59.50 CAD to $70.25 CAD per bbl, with an additional 500 bbls per day of crude oil for the month of March 2020 at $59.08 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 to $1.64 CAD per GJ.

As a result of unprecedented volatility in global commodity markets, the Company will continue to prioritize balance sheet strength, preserve the inherent value of assets, and retain flexibility with its capital program to rapidly respond to fluctuations in the broader commodity price environment. Consistent with this strategy, the Company has taken several steps to ensure strength and resiliency during this period. While the previously announced 2020 capital budget of $70 million is under review, approximately $25 million of spending is committed to date. Bonterra will defer any additional drilling or completions capital investment until economic conditions are more supportive. Further, the Company is actively assessing areas and infrastructure that are uneconomic in the current environment and has shut-in production volumes to protect corporate returns. Lastly, the Company's Board of Directors has elected to suspend its monthly dividend, commencing in April, until the economic environment can support a sustained dividend payment. Bonterra may elect to adjust the amount and timing of capital spending to ensure optimal returns while seeking to further reduce its debt levels. A commitment to sustainability and debt reduction will remain intact through 2020.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending, the amount of monthly dividends, the ability to maintain desired levels of production, control over infrastructure, efficiency in developing and operating properties, and the ability to control costs. The Company's key measures of performance with respect to these drivers include but are not limited to: average daily production volumes, average realized prices, and average operating costs per unit of production. Disclosure of these key performance measures can be found in this MD&A and/or previous interim or annual MD&A disclosures.

Drilling

	Three months ended						Year ended			
	December 31, 2019		September 30, 2019		December 31, 2018		**December 31, 2019**		December 31, 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	**3**	**3.0**	7	7.0	0	0.0	**23**	**23.0**	27	26.9
Crude oil horizontal-non-operated	**1**	**0.1**	5	0.5	2	0.3	**7**	**0.7**	7	1.1
Total	**4**	**3.1**	12	7.5	2	0.3	**30**	**23.7**	34	28.0
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 2019, the Company drilled 23 gross (23.0 net) operated wells and completed 20 gross (20.0 net) operated wells, of which 20 gross (20.0 net) wells were tied-in and placed on production. The remaining three gross (3.0 net) wells commenced production in early Q1 2020.

In addition, seven gross (0.7 net) non-operated wells were drilled, completed, equipped and placed on production in 2019.

Production

	Three months ended			Year ended	
	December 31, 2019	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Crude oil (bbl per day)	**7,255**	7,157	7,756	**7,310**	8,119
NGLs (bbl per day)	**1,016**	1,009	1,025	**986**	995
Natural gas (MCF per day)	**24,697**	23,820	24,045	**24,053**	24,549
Average BOE per day	**12,387**	12,136	12,789	**12,305**	13,206

Annual production averaged 12,305 BOE per day in 2019, compared to 13,206 BOE per day for the same period in 2018, reflecting significantly lower capital spending in 2019 compared to 2018, which led to fewer new wells coming on production. In addition, during 2019 an average of approximately 350 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 ("BC") natural gas wells due to low realized natural gas prices. The BC natural gas wells were placed back on production as gas prices increased in the fourth quarter.

Fourth quarter 2019 production was higher than the previous quarter due to the timing of new wells being brought onto production and the reactivation of the BC natural gas wells in November of 2019.

Cash Netback

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

	Three months ended			Year ended	
$ per BOE	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Production volumes (BOE)	**1,139,615**	1,116,506	1,176,545	**4,491,303**	4,820,186
Gross production revenue	**44.53**	42.38	29.74	**45.14**	46.34
Royalties	**(2.24)**	(3.76)	(3.17)	**(3.18)**	(4.94)
Production costs	**(16.94)**	(14.32)	(14.23)	**(15.51)**	(14.49)
Field netback	**25.35**	24.30	12.34	**26.45**	26.91
General and administrative	**(1.68)**	(1.05)	(1.19)	**(1.53)**	(1.51)
Interest and other	**(3.05)**	(3.35)	(3.08)	**(3.37)**	(3.16)
Cash netback	**20.62**	19.90	8.07	**21.55**	22.24

Cash netbacks decreased in 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.

Cash netbacks for Q4 2019 increased compared to Q3 2019 due to higher realized commodity prices and an adjustment on past crown royalties paid, which were partially offset by higher production costs per BOE.

Oil and Gas Sales

	Three months ended			Year ended	
	December 31, 2019	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Revenue – oil and gas sales ($ 000s)					
Crude oil	**42,297**	43,121	27,801	**176,996**	194,137
NGL	**2,280**	2,085	3,273	**9,300**	14,645
Natural gas	**6,166**	2,114	3,914	**16,453**	14,606
	50,743	47,320	34,988	**202,749**	223,388
Average realized prices:					
Crude oil ($ per barrel)	**63.37**	65.49	38.96	**66.34**	65.51
NGLs ($ per barrel)	**24.39**	22.45	34.73	**25.83**	40.32
Natural gas ($ per MCF)	**2.71**	0.96	1.77	**1.87**	1.63
Average ($ per BOE)	**44.53**	42.38	29.74	**45.14**	46.34
Average BOE per day	**12,387**	12,136	12,789	**12,305**	13,206

Revenue from oil and gas sales in 2019 decreased by $20,639,000, or nine percent, compared to the same period in 2018. The decrease in oil and gas sales was primarily driven by a seven 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 both production volumes and natural gas prices compared to Q3 2019.

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

Royalties

	Three months ended			Year ended	
($ 000s)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Crown royalties	**780**	2,563	2,476	**7,230**	15,157
Freehold, gross overriding and other royalties	**1,770**	1,632	1,254	**7,044**	8,665
Total royalties	**2,550**	4,195	3,730	**14,274**	23,822
Crown royalties – percentage of revenue	**1.5**	5.4	7.1	**3.6**	6.8
Freehold, gross overriding and other royalties – percentage of revenue	**3.5**	3.4	3.6	**3.5**	3.9
Royalties – percentage of revenue	**5.0**	8.8	10.7	**7.1**	10.7
Royalties $ per BOE	**2.24**	3.76	3.17	**3.18**	4.94

Royalties paid by the Company consist of both crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and other royalties. Total royalties for the year ended December 31, 2019 decreased by $1.76 per BOE compared to 2018. The decrease is primarily the result of a crown royalty refund of $2.1 million and lower commodity prices in 2019 than the prior year. The crown royalty refund recorded in the fourth quarter of 2019 was due to a reassessment on past royalties paid.

Production Costs

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Production costs	**19,304**	15,989	16,746	**69,673**	69,861
$ per BOE	**16.94**	14.32	14.23	**15.51**	14.49

Production costs for 2019 did not substantially change from 2018 despite a decrease in production. The increase in costs on a per BOE basis was primarily due to increased trucking as flush production from new wells exceeded facility capacity, increased chemical costs for pipeline integrity and maintenance prevention programs, increased facility turnarounds and shut-in production. Facility turnarounds are not required every year and may not be required again for an additional five years; as such, a disproportionate number of turnarounds were required in 2019 versus prior periods.

Production costs for Q4 2019 increased by $3,315,000 compared to Q3 2019 primarily due to increased well and facility maintenance costs, chemical and power costs due to increased power rates and consumption.

Other Income

	Three months ended			Year ended	
($ 000s)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Investment income	**21**	11	17	**64**	65
Administrative income	**64**	25	43	**144**	176
Gain on sale of property	**70**	3	-	**75**	-
Deferred consideration	**346**	301	302	**1,273**	1,362
Realized loss on risk management contracts	**(443)**	-	-	**(443)**	-
Unrealized loss on risk management contracts	**(76)**	(58)	-	**(134)**	-
	(18)	282	362	**979**	1,603

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 December 31, 2019 was $286,000 (December 31, 2018 – $374,000). There were no dispositions for the years ended December 31, 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 provided and production equipment rentals.

During the third quarter of 2019, 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. For the first half of 2020, Bonterra also entered into further financial derivatives to minimize commodity price risk on future crude oil sales. The financial derivatives outstanding are for a total of 136,500 barrels of crude oil (approximately 1,000 barrels of oil per day for Q1 2020 and 500 barrels of oil per day for Q2 2020) at fixed Edmonton Par prices ranging from $67.75 to $69.60 CAD per barrel for Q1 2020 and $59.50 CAD per barrel for Q2 2020. These contracts are not considered normal sales contracts and are recorded at fair value.

General and Administration (G&A) Expense

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Employee compensation expense	**1,367**	987	696	**4,569**	4,633
Office and administrative expense	**550**	185	699	**2,304**	2,645
Total G&A expense	**1,917**	1,172	1,395	**6,873**	7,278
$ per BOE	**1.68**	1.05	1.19	**1.53**	1.51

Employee compensation expense for 2019 compared to 2018 remained primarily unchanged due to slightly lower 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 2019 decreased by $341,000 compared to 2018 primarily due to a decrease in bank charges, professional consulting fees and the allowance for doubtful accounts expense, which was partially offset by an increase in software and consulting services. The increase in Q4 2019 over Q3 2019 was primarily due to increased bank charges and professional consulting fees.

Finance Costs

($ 000s except $ per BOE)	Three months ended **December 31, 2019**	September 30, 2019	December 31, 2018	Year ended **December 31, 2019**	December 31, 2018
Interest on long-term debt	**3,337**	3,586	3,444	**14,540**	14,560
Other interest	**222**	194	239	**801**	905
Interest expense	**3,559**	3,780	3,683	**15,341**	15,465
$ per BOE	**3.12**	3.39	3.13	**3.42**	3.21
Unwinding of the discounted value of decommissioning liabilities	**798**	731	762	**3,019**	3,069
Total finance costs	**4,357**	4,511	4,445	**18,360**	18,534

Interest on long-term debt remained relatively unchanged for 2019 compared to 2018 due to increased interest rates as a result of a higher net debt to earnings before income taxes, depletion and amortization (or "EBITDA" as defined by the Company's bank facility) ratio for 2019 due to decreased EBITDA from reduced production. Interest costs for 2019 were partially offset by lower average long-term debt outstanding of approximately $7,828,000. 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 $7,740,000. 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 12 of the December 31, 2019 audited annual financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,007,000.

Share-option Compensation

($ 000s)	Three months ended **December 31, 2019**	September 30, 2019	December 31, 2018	Year ended **December 31, 2019**	December 31, 2018
Share-option compensation	**319**	649	449	**2,147**	2,710

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 $563,000 in 2019 compared to 2018. This decline is primarily due to the higher share price volatility on most of the options issued in 2017 (which were fully amortized in 2018) relative to the options issued in the fourth quarter of 2018 (which will be fully amortized in 2019). In addition, no options were issued in Q4 2019 compared to 1,031,000 options being issued in Q4 2018.

Based on the outstanding options as of December 31, 2019, the Company has an unamortized expense of $172,000, of which $126,000 will be recorded for 2020 and $46,000 thereafter. For more information about options issued and outstanding, refer to Note 16 of the December 31, 2019 audited annual financial statements.

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

($ 000s)	Three months ended **December 31, 2019**	September 30, 2019	December 31, 2018	Year ended **December 31, 2019**	December 31, 2018
Depletion and depreciation	**23,718**	22,973	23,189	**89,861**	91,453
Exploration and evaluation	**-**	-	-	**-**	291

The provision for depletion and depreciation increased in 2019 compared to 2018 primarily due to decreased production volumes. The increase in the provision for depletion and depreciation in Q4 2019 compared to Q3 2019 is due to increased production volumes and a decrease in the December 31, 2019 proved plus probable developed reserves.

The E&E expenses relate to expired leases.

There were no impairment provisions recorded for the year ended December 31, 2019 or 2018.

Taxes

The Company recorded a deferred income tax recovery of $19,475,000 (2018 – $3,921,000 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 15 of the December 31, 2019 annual audited financial statements.

Net Earnings (Loss)

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Net earnings (loss)	**(1,389)**	(1,276)	(10,909)	**21,923**	7,167
$ per share – basic	**(0.04)**	(0.04)	(0.33)	**0.66**	0.22
$ per share – diluted	**(0.04)**	(0.04)	(0.33)	**0.66**	0.22

Net earnings for 2019 increased by $14,756,000 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 2019 was partially offset by a decrease in oil and gas sales.

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 (December 31, 2018 – unrealized loss of $376,000). Realized gains decrease accumulated other comprehensive income as these gains are transferred to retained earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments, including the investment in a related party, net of tax.

Cash Flow from Operations

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2019**	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
Cash flow from operations	**20,767**	19,774	20,509	**81,132**	115,963
$ per share – basic	**0.62**	0.59	0.61	**2.43**	3.48
$ per share – diluted	**0.62**	0.59	0.61	**2.43**	3.48

In 2019, cash flow from operations decreased by $34,831,000 compared to 2018. This was primarily due to a decrease in revenue from oil and gas sales, non-cash working capital and additional decommissioning liabilities settled.

The quarter-over-quarter increase in cash flow of $993,000 was also primarily due to an increase in revenue from oil and gas sales, non-cash working capital and a crown royalty reassessment partially offset by an increase in production costs.

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 December 31, 2019 of $155,000 (December 31, 2018 – $258,000). The Company provides marketing services for Pine Cliff. All services performed were charged at estimated fair value. As at December 31, 2019, the Company had an account receivable from Pine Cliff of $47,000 (December 31, 2018 – $71,000).

As at December 31, 2019, a loan to Bonterra provided by the Company's CEO, Chairman of the Board and major shareholder totaled $12,000,000 (December 31, 2018 – $12,000,000). On December 1, 2019, the loan's interest rate increased from the Canadian charged bank prime less 5/8th of one percent to five and a half 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 in 2019 was $421,000 (December 31, 2018 – $362,000).

Liquidity and Capital Resources

NET DEBT TO CASH FLOW FROM OPERATIONS

Bonterra continues to focus on monitoring overall debt while managing its cash flow, capital expenditures and dividend payments. The Company's net debt to twelve-month trailing cash flow ratio as of December 31, 2019 was 3.6 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 Company's twelve-month trailing cash flow. Compared to year end 2018, net debt decreased by $36,131,000 in 2019 due to a stronger focus on debt reduction, a lower capital spending program and reduced dividend payments compared to the prior year. 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)	**December 31, 2019**	December 31, 2018
Working capital deficiency	**19,745**	30,281
Long-term bank debt	**273,065**	298,660
Net Debt	**292,810**	328,941

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

Net debt is a combination of long-term bank debt and working capital. Net debt for December 31, 2019 decreased by $36,131,000 compared to December 31, 2018 primarily due to a stronger focus on debt reduction, a lower capital spending program and reduced dividend payments compared to the prior year.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and adjustments of dividend payments. Included in the working capital deficiency as at December 31, 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. 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 19 of the December 31, 2019 audited annual financial statements.

CAPITAL EXPENDITURES

During the year ended December 31, 2019, the Company incurred capital expenditures of $53,627,000 (December 31, 2018 – $78,737,000). Of the total capital invested, $44,551,000 was directed to the drilling and completion of 30 gross (23.7 net) wells and the tie-in of 27 gross (20.7 net) wells, with the remaining three wells brought on production in Q1 2020. An additional $9,076,000 was spent on related infrastructure costs, recompletions and other capital expenditures.

LIABILITY MANAGEMENT RATIO ("LMR") UPDATE

In 2019, 97 percent of the Company's production was in the province of Alberta. The Company currently has an LMR rating of 1.86 in Alberta, which has remained relatively unchanged from 2018 as lower drilling activity led to lower production volumes and a lower three-year average for crude oil pricing. Bonterra has instituted an abandonment program in 2020 to reclaim 150 to 170 inactive well bores over two years in order to increase its LMR ratio. Bonterra does not anticipate any regulatory impediments given its current LMR.

LONG-TERM DEBT

Long-term debt represents the outstanding amounts drawn on the Company's bank facility as described in the notes to the Company's audited annual financial statements. As of December 31, 2019, the Company has a bank facility with a limit of $325,000,000 (December 31, 2018 – $380,000,000) that is comprised of a $286,765,000 syndicated revolving credit facility and a $38,235,000 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 $325,000,000 at December 31, 2019 totaled $273,065,000 (December 31, 2018 – $298,660,000), nine percent lower than year-end 2018. The interest rates for the year ended December 31, 2019 on the Company's Canadian prime rate loan and Banker's Acceptances range 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 13 of the December 31, 2019 audited annual financial statements.

SHAREHOLDERS' EQUITY

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

The Company is 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.

	December 31, 2019		December 31, 2018	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**33,388,796**	**765,276**	33,310,796	763,977
Issued pursuant to the Company's share option plan	**–**	**–**	78,000	1,143
Transfer from contributed surplus to share capital		**–**		156
Balance, end of period	**33,388,796**	**765,276**	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 16 of the December 31, 2019 audited annual financial statements.

COMMITMENTS

The Company has entered into firm service gas transportation agreements in which the Company guarantees that certain minimum volumes of natural gas will be shipped on various gas transportation systems. Bonterra uses firm service delivery with TransCanada Pipeline on approximately 90 percent of its natural gas production. Given that substantially all of Bonterra's current natural gas production is from the solution gas in oil wells, this will reduce transportation curtailments associated with interruptible service, therefore decreasing restrictions on oil production. The terms of the various agreements expire in one to seven years.

The Company has office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 3.9 years.

Future minimum payments for the firm service gas transportation agreements using current tariff rates and the non-cancellable building and office equipment leases as at December 31, 2019 are as follows:

($ 000s)	2020	2021	2022	2023	2024	Thereafter	Total
Firm service commitments	194	148	121	121	113	35	732
Office lease commitments	571	499	501	487	-	-	2,058
Total	765	647	622	608	113	35	2,790

Dividend Policy

For the year ended December 31, 2019, the Company declared and paid dividends of $4,007,000 ($0.12 per share) (December 31, 2018 – $36,985,000) ($1.11 per share). Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, broad market conditions, cash flow from operations, debt levels and capital expenditures.

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.

On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing in April, in response to significant volatility in commodity markets. The dividend is expected to be reestablished when the economic environment can support a sustained dividend payment.

QUARTERLY FINANCIAL INFORMATION

	2019			
For the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Revenue – oil and gas sales	**50,743**	47,320	54,852	49,834
Cash flow from operations	**20,767**	19,774	25,468	15,123
Net earnings (loss)	**(1,389)**	(1,276)	23,131	1,457
Per share – basic	**(0.04)**	(0.04)	0.69	0.04
Per share – diluted	**(0.04)**	(0.04)	0.69	0.04

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

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 experienced a significant decrease in the realized price for Canadian crude oil due to extremely wide differentials, which negatively impacted Bonterra's Q4 2018 net earnings and cash flow, as well as its 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.

DRILLING LOCATIONS

This MD&A discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations, which are sometimes collectively referred to as "booked locations", are derived from the independent reserves evaluation prepared by Sproule Associates Ltd. as of December 31, 2019 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on Bonterra's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Of the 700 net drilling locations identified herein, 305 are proved locations, six are probable locations and 389 are unbooked locations. Unbooked locations have been identified by management as an estimation based on industry practice and internal review of our multi-year drilling activities, which include an evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Bonterra will drill all unbooked drilling locations and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves or production. No locations have been assigned resources other than reserves ("ROTR"). All drilling counts cited herein are net.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim fillings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief Financial Officer of Bonterra evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Bonterra's DC&P were effective at December 31, 2019.

Internal Controls Over Financial Reporting

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

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;
2. Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and
3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

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

The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial period end of the Company and concluded that such internal controls over financial reporting are effective as of December 31, 2019.

It should be noted that while Bonterra's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and are effective; they do not expect that these controls will prevent all errors and fraud.

Management's Responsibility for Financial Statements

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

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

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

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

March 10, 2020

Robb D. Thompson
Chief Financial Officer

March 10, 2020

Independent Auditor's Report

To the Shareholders of Bonterra Energy Corp.

Opinion

We have audited the financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statement of financial position as at December 31, 2019 and 2018, and the statement of comprehensive income, statement of changes in equity and statement of cash flow for the years then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2019 and 2018, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

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

Other Information

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

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

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

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

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

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

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

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

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

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

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

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

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

Deloitte LLP

Chartered Professional Accountants

Calgary, Alberta
March 10, 2020

Statement of Financial Position

As at ($ 000s)	Note	**December 31, 2019**	December 31, 2018
ASSETS			
CURRENT			
Accounts receivable		**21,764**	7,797
Crude oil inventory		**672**	613
Prepaid expenses		**3,908**	3,183
Investments		**131**	116
		26,475	11,709
Investment in related party	6	**155**	258
Exploration and evaluation assets	7	**3,980**	4,422
Property, plant and equipment	8	**955,536**	985,773
Investment tax credit receivable	15	**8,861**	8,861
Goodwill	9	**92,810**	92,810
		1,087,817	1,103,833
LIABILITIES			
CURRENT			
Accounts payable and accrued liabilities	10	**25,423**	18,743
Risk management contract	19	**134**	-
Due to related party	11	**12,000**	12,000
Subordinated promissory note	12	**7,500**	10,000
Deferred consideration		**1,163**	1,247
		46,220	41,990
Bank debt	13	**273,065**	298,660
Deferred consideration		**12,266**	13,455
Decommissioning liabilities	14	**138,171**	132,134
Deferred tax liability	15	**114,146**	133,624
		583,868	619,863
SHAREHOLDERS' EQUITY			
Share capital	16	**765,276**	765,276
Contributed surplus		**30,234**	28,087
Accumulated other comprehensive loss		**(748)**	(664)
Retained earnings (deficit)		**(290,813)**	(308,729)
		503,949	483,970
		1,087,817	1,103,833

Commitments and contingencies	20
Subsequent events	19,21

See accompanying notes to these financial statements.

On behalf of the Board:

George F. Fink
Director

Rodger A. Tourigny
Director

Statement of Comprehensive Income

FOR THE YEARS ENDED DECEMBER 31 ($ 000s, except $ per share)	Note	2019	2018
REVENUE			
Oil and gas sales, net of royalties	17	**188,475**	199,566
Other income	18	**283**	241
Deferred consideration		**1,273**	1,362
Loss on risk management contracts	19	**(577)**	-
		189,454	201,169
EXPENSES			
Production		**69,673**	69,861
Office and administration		**2,304**	2,645
Employee compensation		**4,569**	4,633
Finance costs	5	**18,360**	18,534
Share-option compensation		**2,147**	2,710
Depletion and depreciation	8	**89,861**	91,453
Exploration and evaluation	7	**-**	291
		186,914	190,127
EARNINGS BEFORE INCOME TAXES		**2,540**	11,042
TAXES			
Current income tax expense (recovery)	15	**92**	(46)
Deferred income tax expense (recovery)	15	**(19,475)**	3,921
		(19,383)	3,875
NET EARNINGS FOR THE YEAR		**21,923**	7,167
OTHER COMPREHENSIVE INCOME (LOSS)			
Unrealized (loss) on investments		**(88)**	(376)
Deferred taxes on unrealized loss on investments		**4**	51
OTHER COMPREHENSIVE (LOSS) FOR THE YEAR		**(84)**	(325)
TOTAL COMPREHENSIVE INCOME FOR THE YEAR		**21,839**	6,842
NET EARNINGS PER SHARE – BASIC AND DILUTED	16	**0.66**	0.22
COMPREHENSIVE INCOME PER SHARE – BASIC AND DILUTED	16	**0.65**	0.21

See accompanying notes to these financial statements.

Statement of Cash Flow

FOR THE YEARS ENDED DECEMBER 31 ($ 000s)	Note	2019	2018
OPERATING ACTIVITIES			
Net earnings		**21,923**	7,167
Items not affecting cash			
Deferred income taxes		**(19,475)**	3,921
Deferred consideration		**(1,273)**	(1,362)
Share-option compensation		**2,147**	2,712
Depletion and depreciation		**89,861**	91,453
Exploration and evaluation expenditures		**-**	291
Unrealized loss on risk management contracts	19	**134**	-
Gain on sale of property and equipment		**(75)**	-
Unwinding of the discount on decommissioning liabilities	14	**3,019**	3,069
Investment income		**(64)**	(65)
Interest expense		**15,340**	15,465
Change in non-cash working capital accounts:			
Accounts receivable		**(13,854)**	11,749
Crude oil inventory		**(10)**	49
Prepaid expenses		**(725)**	(648)
Investment tax credit receivable		**-**	(27)
Accounts payable and accrued liabilities		**2,129**	(1,000)
Decommissioning expenditures	14	**(2,605)**	(1,346)
Interest paid		**(15,340)**	(15,465)
CASH PROVIDED BY OPERATING ACTIVITIES		**81,132**	115,963
FINANCING ACTIVITIES			
Increase (decrease) of bank debt		**(25,595)**	6,448
Subordinated promissory note		**(2,500)**	(2,500)
Stock option proceeds		**-**	1,143
Dividends		**(4,007)**	(36,985)
CASH USED IN FINANCING ACTIVITIES		**(32,102)**	(31,894)
INVESTING ACTIVITIES			
Investment income received		**64**	65
Exploration and evaluation expenditures	7	**-**	(535)
Property, plant and equipment expenditures	8	**(53,627)**	(78,202)
Proceeds on sale of property		**95**	-
Change in non-cash working capital accounts:			
Accounts payable and accrued liabilities		**4,551**	(6,387)
Accounts receivable		**(113)**	990
CASH USED IN INVESTING ACTIVITIES		**(49,030)**	(84,069)
NET CHANGE IN CASH IN THE YEAR		**–**	–
Cash, beginning of year		**–**	–
CASH, END OF YEAR		**–**	–

See accompanying notes to these financial statements.

Statement of Changes in Equity

FOR THE YEARS ENDED
($ 000's, except number of shares outstanding)

	Numbers of common shares outstanding (Note 16)	Share Capital (Note 16)	Contributed surplus[1]	Accumulated other Comprehensive 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			2,710			2,710
Exercise of options	78,000	1,143				1,143
Transfer to share capital on exercise of options		156	(156)			-
Comprehensive income (loss)				(325)	7,167	6,842
Dividends					(36,985)	(36,985)
DECEMBER 31, 2018	33,388,796	765,276	28,087	(664)	(308,729)	483,970
Share-option compensation			2,147			2,147
Comprehensive income (loss)				(84)	21,923	21,839
Dividends					(4,007)	(4,007)
DECEMBER 31, 2019	**33,388,796**	**765,276**	**30,234**	**(748)**	**(290,813)**	**503,949**

(1) All amounts reported in Contributed Surplus relate to share-option compensation.

(2) Accumulated other comprehensive income is comprised of unrealized gains and losses on investments fair value through other comprehensive income.

See accompanying notes to these financial statements.

Notes to the Financial Statements

As at and for the years ended December 31, 2019 and 2018

1. Nature of Business and Segment Information

Bonterra Energy Corp. ("Bonterra" or the "Company") is a public company listed on the Toronto Stock Exchange (the "TSX") and incorporated under the Business Corporations Act (Alberta). The address of the Company's registered office is Suite 901, 1015-4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

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

2. Basis of Preparation

A) STATEMENT OF COMPLIANCE

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).

The financial statements were authorized for issue by the Company's Board of Directors on March 10, 2020.

B) BASIS OF MEASUREMENT

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

C) FUNCTIONAL AND PRESENTATION CURRENCY

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

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

D) SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

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

E) ADOPTED ACCOUNTING PRONOUNCEMENTS

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 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 right of use assets 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.

IFRS 3 "Business Combinations"

The Company elected to early adopt the amendments to IFRS 3 "Business Combinations" effective January 1, 2019, which has been 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. Significant Accounting Policies

A) REVENUE RECOGNITION

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when or as Bonterra satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, and natural gas liquids usually coincides with title passing to the customer and the customer taking physical possession. The Company principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant. Collection of revenue associated with the sale of crude oil, natural gas and natural gas liquids occurs on or about the 25th of the month following production. Items such as royalties for crown, freehold, gross overriding (GORR) and Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue. Administration fee income is recorded when services are provided.

B) JOINT ARRANGEMENTS

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's interests in such activities. A jointly controlled operation involves the use of assets and other resources of the Company and those of other joint venture participants through contractual arrangements rather than through the establishment of a corporation, partnership or other entity. The Company has no interests in jointly controlled entities. The Company recognizes in its financial statements its interest in assets that it owns, the liabilities and expenses that it incurs and its share of income earned by the joint arrangement.

C) INVENTORIES

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first-in, first-out basis at the lower of cost or net realizable value. The inventory cost for crude oil is determined based on the combined average per barrel operating costs, and depletion and depreciation for the period, while net realizable value is determined based on estimated sales price less transportation costs.

D) INVESTMENTS AND INVESTMENT IN RELATED PARTY

Investments and investment in related party consist of equity securities. The Company's investments are measured as fair value through other comprehensive income ("FVTOCI"), with gains or losses arising from changes in fair value recognized in other comprehensive income and accumulated in the fair value instrument. The cumulative gain or loss will not be reclassified to profit or loss on disposal of the investments. Fair value is determined by multiplying the period end trading price of the investments by the number of common shares held as at period end.

E) EXPLORATION AND EVALUATION ASSETS

General exploration and evaluation ("E&E") expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the asset. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment ("PP&E"). E&E assets are assessed for impairment annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not at amounts above their recoverable amounts.

F) PROPERTY, PLANT AND EQUIPMENT

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost, including expenditures such as drilling costs; the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset; and finance charges on qualifying assets that are directly attributable to bringing the asset into operation and to its present location.

Production Facilities

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

Leases

Leases or contractual obligations are capitalized as right of use assets ("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 the stated rate in the lease contract. If no discount rate is provided, the Company's incremental borrowing rate is used. 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.

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income (loss).

PP&E properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable developed reserve life, when commercial production in an area has commenced. Proved plus probable developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of proved plus probable developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets' estimated economic lives, less estimated salvage value of the assets at the end of their useful lives.

These assets are depreciated as follows:

Production facilities	Declining balance method at 10 percent per year
Furniture, fixtures and other equipment	Declining balance method at 10 to 20 percent per year
Right of use assets	Straight line method over the term of the associated lease

G) BUSINESS COMBINATIONS AND GOODWILL

The purchase price used in a business combination is based on the fair value at the date of acquisition. The business combination is accounted for based on the fair value of the assets acquired and liabilities assumed. All acquisition costs are expensed as incurred. Contingent liabilities are recognized at fair value at the date of the acquisition, and subsequently re-measured at each reporting period until settled. The excess of cost over fair value of the net assets and liabilities acquired is recorded as goodwill.

H) IMPAIRMENT OF ASSETS

Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flow of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flow discounted at the original effective interest rate. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as FVTOCI is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets' carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E, PP&E and goodwill) are grouped together into the smallest group of assets that generate cash flows from continuing use which are largely independent of the cash flow of other assets or groups of assets (the cash-generating unit or "CGU"). Goodwill is allocated to the CGU expected to benefit from the synergies of the combination. The recoverable amount of an asset or a CGU is the greater of its value-in-use ("VIU") and its fair value less costs to sell ("FVLCS"). The Company has a core CGU composed of its Alberta properties and secondary CGUs for its British Columbia (BC) and Saskatchewan properties.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income (loss). Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

In respect of assets other than goodwill, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the impairment loss has reversed. If the amount of the impairment loss reverses in a subsequent period and the reversal can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized and recorded in the statement of comprehensive income (loss). An impairment loss in respect of goodwill cannot be reversed.

I) DEFERRED CONSIDERATION

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

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

J) DECOMMISSIONING LIABILITIES

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk-free rates are dealt with prospectively by recording an adjustment to the decommissioning liabilities, and a corresponding adjustment to PP&E. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the liability can be made. On a periodic basis, management will review these estimates and changes and if there are any, they will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved plus probable developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and any remaining balance of actual costs is recorded in the statement of comprehensive income (loss).

K) INCOME TAXES

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income (loss) or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each period end and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset or liability.

L) SHARE-OPTION COMPENSATION

The Company accounts for share-option compensation using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Share-option payments are recognized through the statement of comprehensive income (loss) over the vesting period with a corresponding amount reflected in contributed surplus in equity. For awards issued in tranches that vest at different times, the fair value of each tranche is recognized over its respective vesting period.

At the grant date and at the end of each reporting period, the Company assesses and re-assesses for subsequent periods its estimates of the number of awards that are expected to vest and recognizes the impact of the revisions in the statement of comprehensive income (loss). Upon exercise of share-based options, the proceeds received net of any transaction costs and the fair value of the exercised share-based options is credited to share capital.

Employees may elect to have the Company settle any or all options vested and exercisable using a cashless equity settlement. In connection with any such exercise, an employee shall be entitled to receive, without any cash payment (other than the taxes required to be paid in connection with the exercise), whole shares of the Company. The number of shares under option multiplied by the difference of the fair value at the time of exercise less the option exercise price, divided by the fair value at the time of exercise, determines the number of whole shares issued.

M) FINANCIAL INSTRUMENTS

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

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

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

N) FAIR VALUE MEASUREMENT

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related party, subordinated promissory note and bank debt on the statement of financial position are carried at amortized cost. Investments and investment in related party are carried at fair value. All of the investments are transacted in active markets. Bonterra determines the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

O) RISK MANAGEMENT CONTRACTS

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur. Bonterra's risk management contracts have been assessed on the fair value hierarchy described above and are all considered Level 2.

P) NET EARNINGS AND COMPREHENSIVE INCOME PER SHARE

Per share amounts are calculated by dividing the net earnings or comprehensive income (loss) attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share-options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share-options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

4. Significant Accounting Estimates and Judgments

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. The following are the estimates and judgments applied by management that most significantly affect the Company's financial statements.

EXPLORATION AND EVALUATION EXPENDITURES

E&E costs are initially capitalized with the intent to establish commercially viable reserves. E&E assets include undeveloped land and costs related to exploratory wells. The Company is required to make estimates and judgments about future events and circumstances regarding the future economic viability of extracting the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made that the underlying reserves are not viable, the E&E costs will be impaired and charged to net earnings.

IMPAIRMENT OF NON-FINANCIAL ASSETS

PP&E and goodwill are aggregated into CGUs based on their ability to generate largely independent cash flows and are assessed for impairment. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, and similar market risks. Oil and gas prices and other assumptions will change in the future, which may impact the Company's recoverable amounts and may therefore require a material adjustment to the carrying value of PP&E. The determination of the Company's CGUs is subject to management's judgment. The Company has a core CGU composed of its Alberta properties and secondary CGUs for its BC and Saskatchewan properties.

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

The Company performs an impairment test on all of its CGUs for any potential impairment or related recovery at least annually or when impairment or recovery indicators arise. For the year ended December 31, 2019 the Company also performed an impairment test due to a decrease in market capitalization for Bonterra and other Canadian Oil and Gas producers. In making these evaluations, the Company uses the following information:

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

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

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

b) Crude oil and natural gas prices – Forward price estimates of the crude oil and natural gas prices are used in the discounted cash flow model. These prices are adjusted for quality differentials, heat content and distance to market. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

The following table from external sources outlines the forecast benchmark commodity prices used in the impairment calculation as at December 31, 2019.

BONTERRA'S KEY ASSUMPTIONS FOR IMPAIRMENT

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030(2)
WTI Crude oil $US/Bbl(1)	61.00	65.00	67.00	68.34	69.71	71.10	72.52	73.97	75.45	76.96	78.50
AECO C-Spot $Mmbtu(1)	2.04	2.27	2.81	2.89	2.98	3.06	3.15	3.24	3.33	3.42	3.51
Exchange rate US$/Cdn$	0.76	0.77	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

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

(2) Forecast benchmarks commodity prices are assumed to increase by 2.0% in each year after 2030 to end of the reserve life.

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

With the current key assumptions listed above, the Company performed impairment tests for each CGU and concluded that no reasonable change in the key assumptions, such as a five percent change in commodity prices or a two percent change in the discount rate, would result in an impairment being recorded.

RESERVES ESTIMATION

The capitalized costs of oil and gas properties and deferred consideration are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors and future oil and gas prices. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves.

RISK MANAGEMENT CONTRACT

The Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in net earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party futures quotes for commodities. Any realized or unrealized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

SHARE-OPTION COMPENSATION

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value requires the determination of the most appropriate valuation model for a grant, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk-free interest rates, volatility and dividend yield.

DEFERRED CONSIDERATION

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

DECOMMISSIONING AND RESTORATION COSTS

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of the Company's oil and gas properties. Provisions for decommissioning liabilities are based on cost estimates which can vary in response to many factors including timing of abandonment, inflation, changes in legal requirements, new restoration techniques and interest rates.

INCOME TAXES

The Company recognizes the net deferred tax benefit or expense related to deferred income tax assets or liabilities to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of investment tax credit receivable requires the Company to make significant estimates related to expectations of future taxable income. The provision for income taxes is based on judgments in applying income tax law and estimates of the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. The ability to realize on the deferred tax assets and investment tax credit receivable that are recorded on the balance sheet may be compromised to the extent that any interpretation of tax law is challenged or taxable income differs significantly from estimates.

Further details regarding accounting estimates and judgments are disclosed in Note 3.

5. Finance Costs

A breakdown of finance costs for the years ended:

($ 000s)	**December 31, 2019**	December 31, 2018
Interest expense on bank debt	**14,540**	14,561
Interest expense on amounts owing to related party	**421**	362
Interest expense on subordinated promissory note and other	**380**	542
Unwinding of the fair value of decommissioning liabilities	**3,019**	3,069
	18,360	18,534

6. Investment in Related Party

The investment consists of 1,034,523 (December 31, 2018 – 1,034,523) common shares in Pine Cliff Energy Ltd. ("Pine Cliff"), a company with some common directors with Bonterra. The investment in Pine Cliff represents less than one percent ownership in the outstanding common shares of Pine Cliff and is recorded at fair value through other comprehensive income. The common shares of Pine Cliff trade on the TSX under the symbol PNE.

7. Exploration and Evaluation Assets

($ 000s)	
COST AND CARRYING AMOUNT	
Balance at January 1, 2018	4,217
Additions	535
Transfers to property, plant and equipment	(39)
Expiry of exploration and evaluation assets	(291)
BALANCE AT DECEMBER 31, 2018	4,422
Transfers to property, plant and equipment	(442)
BALANCE AT DECEMBER 31, 2019	**3,980**

8. Property, Plant and Equipment

COST ($ 000s)	Oil and Gas Properties	Production Facilities	Furniture Fixtures & Other Equipment	Total Property Plant & Equipment
Balance at January 1, 2018	1,318,063	324,729	2,181	1,644,973
Additions	60,779	17,319	104	78,202
Transfers from exploration and evaluation assets	39	-	-	39
Adjustment to decommissioning liabilities (Note 14)	3,780	-	-	3,780
BALANCE AT DECEMBER 31, 2018	1,382,661	342,048	2,285	1,726,994
Additions	38,213	15,360	54	53,627
Transfers from exploration and evaluation assets	442	-	-	442
Adjustment to decommissioning liabilities (Note 14)	5,623	-	-	5,623
Disposal	(16)	-	(84)	(100)
BALANCE AT DECEMBER 31, 2019	**1,426,923**	**357,408**	**2,255**	**1,786,586**

ACCUMULATED DEPLETION AND DEPRECIATION ($ 000s)	Oil and Gas Properties	Production Facilities	Furniture Fixtures & Other Equipment	Total Property Plant & Equipment
Balance at January 1, 2018	(529,434)	(118,757)	(1,707)	(649,898)
Depletion and depreciation	(75,198)	(16,170)	(85)	(91,453)
Other	130	-	-	130
BALANCE AT DECEMBER 31, 2018	(604,502)	(134,927)	(1,792)	(741,221)
Depletion and depreciation	(73,718)	(16,069)	(74)	(89,861)
Disposal and other	(45)	-	77	32
BALANCE AT DECEMBER 31, 2019	**(678,265)**	**(150,996)**	**(1,789)**	**(831,050)**

CARRYING AMOUNTS AS AT: ($ 000s)				
December 31, 2018	778,159	207,121	493	985,773
DECEMBER 31, 2019	**748,658**	**206,412**	**466**	**955,536**

There were no impairment losses or reversals recorded in the statement of comprehensive income for the years ended December 31, 2019 and 2018.

9. Goodwill

The amount recorded as goodwill has been fully allocated to the primary CGU, Alberta, Canada. There was no impairment loss recorded in the statement of comprehensive income (loss) for the years ended December 31, 2019 and 2018.

10. Accounts Payable and Accrued Liabilities

($ 000s)	**December 31, 2019**	December 31, 2018
Accounts payable	**15,744**	14,489
Accrued liabilities	**9,679**	4,254
	25,423	18,743

11. Transactions with Related Parties

As at December 31, 2019, a loan to Bonterra provided by the Company's CEO, Chairman of the Board and major shareholder totaled $12,000,000 (December 31, 2018 – $12,000,000). On December 1, 2019, the loan's interest rate increased from the Canadian charged bank prime less 5/8th of one percent to five and a half 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 2019 was $421,000 (December 31, 2018 – $362,000).

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 December 3, 2019, the Company had an account receivable from Pine Cliff of $47,000 (December 31, 2018 – $71,000).

COMPENSATION FOR KEY MANAGEMENT PERSONNEL

($ 000s)	**December 31, 2019**	December 31, 2018
Compensation	**1,708**	1,526
Share-based payments	**961**	1,178
Total compensation	**2,669**	2,704

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

12. Subordinated Promissory Note

As at December 31, 2019, Bonterra had $7,500,000 (December 31, 2018 – $10,000,000) outstanding on a subordinated note to a private investor. On December 1, 2019, the loan's interest rate increased from five percent to five and a half percent. The subordinated promissory note is not callable until after June 30, 2020 and is then 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 2019 was $378,000 (December 31, 2018 – $514,000).

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility.

13. Bank Debt

As at December 31, 2019, the Company has a total bank facility of $325,000,000 (December 31, 2018 – $380,000,000), comprised of a $286,765,000 syndicated revolving credit facility and a $38,235,000 non-syndicated revolving credit facility. The amount drawn under the total bank facility at December 31, 2019 was $273,065,000 (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. 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 is 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 December 31, 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 financial covenants on the bank facility:

- The Company cannot exceed $325,000,000 in consolidated debt (comprised of due to related party, subordinated promissory note and long-term bank debt). As at December 31, 2019 consolidated debt totaled $292,565,000.
- 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 four 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 December 31, 2019, the Company is in compliance with all covenants.

14. Decommissioning Liabilities

At December 31, 2019, the Company used a 2.0 percent inflation rate (December 31, 2018 – 2.0 percent inflation rate) and a risk-free nominal rate of 2.3 percent (December 31, 2018 – 2.32 percent) to calculate the present value of the decommissioning provision. In 2019, due to forces currently influencing global capital markets, long-term risk-free nominal rates in Canada declined below target inflation rates, implying a negative real rate of return. The Company determined that applying these rates to current cost estimates would not provide an accurate measurement of the decommissioning liability as observable stand-alone risk-free real rates of return continue to be positive. To provide a more accurate measurement of the liability, the Company applied a risk-free real return rate of 0.3 percent to estimate the present value of the decommissioning provision at December 31, 2019, resulting in a change in estimate. The risk-free real return rate represents an observable, market based risk-free rate of return after adjusting for inflation. Changes in the measurement of the decommissioning provision are added to, or deducted from, the cost of the related asset in property, plant and equipment. When a re-measurement of the decommissioning provision relates to a retired asset, the amount is recorded in the statement of comprehensive income (loss).

At December 31, 2019, the estimated total uninflated and undiscounted amount required to settle the decommissioning liabilities was $155,614,000 (December 31, 2018 – $150,602,000). These obligations will be settled at the end of the useful lives of the underlying assets, which extend up to 50 years into the future.

($ 000s)	**December 31, 2019**	December 31, 2018
DECOMMISSIONING LIABILITIES, JANUARY 1	**132,134**	126,631
Changes in estimate	**5,623**	3,780
Liabilities settled during the period	**(2,605)**	(1,346)
Unwinding of the discount on decommissioning liabilities	**3,019**	3,069
DECOMMISSIONING LIABILITIES, END OF YEAR	**138,171**	132,134

15. Income Taxes

($ 000s)	**December 31, 2019**	December 31, 2018
Deferred tax asset (liability) related to:		
Investments	**81**	82
Exploration and evaluation assets and property, plant and equipment	**(149,134)**	(172,449)
Investment tax credits	**(2,041)**	(2,392)
Decommissioning liabilities	**31,824**	35,676
Corporate tax losses carried forward	**6,714**	7,354
Share issue costs	**-**	6
Financial derivative	**31**	-
Corporate capital tax losses carried forward	**7,488**	8,777
Unrecorded benefits of capital tax losses carried forward	**(7,488)**	(8,777)
Unrecorded benefits of successored resource related pools	**(1,621)**	(1,901)
Deferred tax asset (liability)	**(114,146)**	(133,624)

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

($ 000s)	**December 31, 2019**	December 31, 2018
Earnings (loss) before taxes	**2,540**	11,042
Combined federal and provincial income tax rates	**26.67%**	27.00%
Income tax provision calculated using statutory tax rates	**677**	2,981
Increase (decrease) in taxes resulting from:		
Change in statutory tax rates[1]	**(18,946)**	-
Share-option compensation	**573**	732
Change in unrecorded benefits of tax pools	**(1,569)**	78
Change in estimates and other	**(118)**	84
	(19,383)	3,875

(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	77,467
Canadian oil and gas property expenditures	10	84,635
Canadian development expenditures	30	126,556
Canadian exploration expenditures	100	8,587
Federal income tax losses carried forward[1]	100	42,385
Provincial income tax losses carried forward[2]	100	3,968
		343,598

(1) Federal income tax losses carried forward expire in the following years: 2035 – $6,323,000; 2036 – $35,853,000; 2037 – $209,000.

(2) Provincial income tax losses carried forward expire in the following years: 2036 – $3,759,000; 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.

16. Shareholders' Equity

AUTHORIZED

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

	December 31, 2019		December 31, 2018	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**33,388,796**	**765,276**	33,310,796	763,977
Issued pursuant to the Company's share option plan	**-**	**-**	78,000	1,143
Transfer from contributed surplus to share capital		**-**		156
Balance, end of year	**33,388,796**	**765,276**	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 year ended December 31 is as follows:

	December 31, 2019	December 31, 2018
Basic shares outstanding	**33,388,796**	33,327,777
Dilutive effect of share options(1)	**-**	493
Diluted shares outstanding	**33,388,796**	33,328,270

(1) The Company did not include 1,945,000 share-options (December 31, 2018 – 2,775,000) in the dilutive effect of share-options calculations as these share-options were anti-dilutive.

For the year ended December 31, 2019, the Company declared and paid dividends of $4,007,000 ($0.12 per share) (December 31, 2018 – $36,985,000 ($1.11 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 December 31, 2019 and changes during the year ended are presented below:

	Number of options	Weighted average exercise price
At January 1, 2018	2,806,000	$19.48
Options granted	1,073,000	6.39
Options exercised	(78,000)	14.67
Options forfeited	(53,000)	19.01
Options expired	(954,000)	28.23
At December 31, 2018	2,794,000	$11.62
Options granted	60,000	5.79
Options forfeited	(130,000)	11.24
Options expired	(779,000)	14.93
AT DECEMBER 31, 2019	**1,945,000**	**$10.13**

The following table summarizes information about options outstanding and exercisable as at December 31, 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	1,041,000	1.2 years	$5.92	895,000	$5.93
10.01 – 15.00	818,000	0.8 years	14.55	810,000	14.56
15.01 – 25.00	86,000	1.1 years	19.05	23,000	20.23
$ 5.00 – $ 25.00	1,945,000	1.0 years	$10.13	1,728,000	$10.16

The Company records compensation expense over the vesting period, which ranges between one and three years, based on the fair value of options granted to directors, officers and employees. In 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:

	December 31, 2019	December 31, 2018
Weighted-average risk free interest rate (%)(1)	**1.62**	1.93
Weighted-average expected life (years)	**2.0**	1.2
Weighted-average volatility (%)(2)	**49.06**	46.45
Forfeiture rate (%)	**7.37**	7.55
Weighted average dividend yield (%)	**2.05**	2.22

(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.

17. Oil and Gas Sales, Net of Royalties

($ 000s)	**December 31, 2019**	December 31, 2018
Oil and gas sales		
Crude oil	**176,996**	194,137
Natural gas liquids	**9,300**	14,645
Natural gas	**16,453**	14,606
	202,749	223,388
Less royalties:		
Crown	**(7,230)**	(15,157)
Freehold, gross overriding royalties and other	**(7,044)**	(8,665)
	(14,274)	(23,822)
Oil and gas sales, net of royalties	**188,475**	199,566

18. Other Income

($ 000s)	**December 31, 2019**	December 31, 2018
Investment income	**64**	65
Administrative income	**144**	176
Gain on sale of property and equipment	**75**	-
Other income	**283**	241

19. Financial Risk Management

FINANCIAL RISK FACTORS

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Common share investments
- Due to related party
- Bank debt
- Subordinated promissory note

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, liquidity risk and equity price risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

The Company may enter into various risk management contracts to manage the Company's exposure to commodity price fluctuations. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

CAPITAL RISK MANAGEMENT

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of net debt (total debt adjusted for working capital) to cash flow from operating activities. This ratio is calculated using each quarter end net debt divided by the preceding twelve months' cash flow. Management believes that a net debt level as high as one and a half year's cash flow is still an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs. During the current year the Company had a net debt to cash flow level of 3.6:1 compared to 2.8:1 in 2018. The increase in net debt to cash flow ratio is primarily due to a $34,831,000 decrease in cash flow due to a decrease in production volumes, which was partially offset by reducing net debt by $36,131,000 using excess cash flow from operations.

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

Section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

a) Net Debt to Cash Flow Ratio

The net debt and cash flow amounts are as follows:

($ 000s)	**December 31, 2019**	December 31, 2018
Bank debt	**273,065**	298,660
Current liabilities	**46,220**	41,990
Current assets	**(26,475)**	(11,709)
Net debt	**292,810**	328,941
Cash flow from operations	**81,132**	115,963
Net debt to cash flow ratio	**3.6**	2.8

b) Risks and Mitigation

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

COMMODITY PRICE RISK

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. The Company has assumed the risk in respect of commodity prices, except for a small portion of physical delivery sales and risk management contracts to manage commodity risk on the Company's higher operating cost areas.

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.

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 December 31, 2019, the Company has the following physical delivery sales contracts in place.

Product	Type of Contract	Volume	Term	Contract Price
Oil	Fixed price – MSW Stream index(1)	1,000 BBL/day	January 1 to March 31, 2020	$64.46 CAD/BBL
Gas	Fixed Price – AECO(2)	2,500 GJ/day	April 1 to October 31, 2020	$1.55 CAD/GJ
Gas	Fixed Price – AECO(2)	2,500 GJ/day	April 1 to October 31, 2020	$1.64 CAD/GJ

(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.

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

Subsequent to December 31, 2019, the Company entered into the following physical delivery sales contracts.

Product	Type of Contract	Volume	Term	Contract Price
Oil	Fixed price – MSW Stream index	500 BBL/day	April 1 to June 30, 2020	$70.25 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	April 1 to June 30, 2020	$62.00 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	March 1 to March 31, 2020	$59.08 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	April 1 to June 30, 2020	$62.91 CAD/BBL

RISK MANAGEMENT CONTRACTS

($ 000s)	**December 31, 2019**	December 31, 2018
Risk management contracts		
Realized loss	**(443)**	-
Unrealized loss	**(134)**	-
	(577)	-

The Company also enters into financial derivative instruments or risk management contracts to manage commodity price risk. These contracts are not considered normal executory sales contracts and are recorded at fair value in the financial statements. The Company has entered into the following risk management contracts during the year ended December 31, 2019.

Product	Type of Contract	Volume	Term	Contract Price
Oil	Fixed price – MSW Stream index	500 BBL/day	October 1 to December 31, 2019	$65.00 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	October 1 to December 31, 2019	$63.00 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	November 1 to December 31, 2019	$62.90 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	January 1 to March 31, 2020	$67.75 CAD/BBL
Oil	Fixed price – MSW Stream index	500 BBL/day	January 1 to March 31, 2020	$69.60 CAD/BBL

On March 4, 2020, the Company also entered into a financial derivative for the period of April 1, 2020 to June 30, 2020 for a total of 45,500 barrels of oil (approximately 500 barrels of oil per day) at a fixed MSW stream index price of $59.50 CAD per barrel.

INTEREST RATE RISK

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $286,765,000 syndicated revolving operating line, $38,235,000 non-syndicated operating line, $12,000,000 due to a related party and a $7,500,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, are at bank prime plus or minus various percentages as well as by means of banker's acceptances (BAs) within the Company's credit facility. The subordinated promissory note is at a fixed interest rate of five percent. The Company manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its BAs but in no circumstances do the terms exceed six months.

SENSITIVITY ANALYSIS

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $2,007,000.

EQUITY PRICE RISK

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

FOREIGN EXCHANGE RISK

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company, however, is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

CREDIT RISK

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

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

Of the $21,764,000 accounts receivable balance at December 31, 2019 (December 31, 2018 – $7,797,000) over 75 percent (2018 – 74 percent) relates to product sales with national and international oil and gas companies.

On a quarterly basis, the Company assesses if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2019, there was no material impairment provision required on any of the financial assets of the Company. The Company does have a credit risk exposure as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days' notice if payments are not received.

At December 31, 2019, approximately $276,000 or one percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2018 – $397,000 or five percent). The majority of these accounts are due from various joint venture partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2019 is $1,232,000 (December 31, 2018 – $1,402,000) with the expense being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable. There are no material financial assets that the Company considers past due.

LIQUIDITY RISK

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company maintains bank facilities determined by a portfolio of high-quality, long reserve life oil and gas assets.

20. Commitments and Financial Liabilities

The Company has the following maturity schedule for its financial liabilities and commitments:

($ 000s)	Recognized on Financial Statements	Less than 1 year	Over 1 year to 3 years	Over 3 years to 5 years	Over 5 years to 7 years
Accounts payable and accrued liabilities	Yes – Liability	25,423	-	-	-
Due to related parties	Yes – Liability	12,000	-	-	-
Subordinated promissory note	Yes – Liability	7,500	-	-	-
Bank Debt	Yes – Liability	-	273,065	-	-
Firm service commitments	No	194	269	234	35
Office lease commitments	No	571	1,000	487	-
Total		45,688	274,334	721	35

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to seven years. The future minimum payment amounts for the firm service gas transportation agreements are calculated using current tariff rates.

The Company also has non-cancellable office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 3.9 years.

21. Subsequent Events

I) DIVIDENDS

Subsequent to December 31, 2019, the Company declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 2, 2020	January 15, 2020	0.01	January 31, 2020
February 3, 2020	February 14, 2020	0.01	February 28, 2020
March 2, 2020	March 16, 2020	0.01	March 31, 2020

On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing in April 2020.

II) SHARE OPTIONS

On February 19, 2020 the Company granted 993,200 share options to employees and directors with an exercise price of $3.14, based on the market price immediately preceding the date of grant. The share options vest between one and two years from the grant date and expire between February 18, 2022 and 2023.

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Corporate Information

Board of Directors

G. F. Fink – Chairman
G. J. Drummond
R. M. Jarock
R. A. Tourigny
A. M. Walsh

Officers

G. F. Fink, CEO and Chairman of the Board
R. D. Thompson, CFO and Corporate Secretary
A. Neumann, Chief Operating Officer
B. A. Curtis, Senior VP, Business Development

Registrar and Transfer Agent

Odyssey Trust Company

Auditors

Deloitte LLP

Solicitors

Borden Ladner Gervais LLP

Bankers

CIBC
National Bank of Canada
The Toronto Dominion Bank
ATB Financial
Business Development Bank of Canada

Head Office

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