International exploration & production

Management's Discussion & Analysis

Three and Nine Months Ended
December 31, 2019 and 2018

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at end for the three and nine months ended December 31, 2019.

This MD&A dated February 11, 2020 should be read in conjunction with the Company's interim consolidated financial statements and related notes for the quarter ended December 31, 2019. The interim consolidated financial statements of the Company have been prepared in accordance with International Accounting Standards (IAS) 34.

The functional currency of the Company's operating subsidiary is the Australian dollar ("AUS"); the functional currency of the Company is the Canadian dollar ("CAD"). The Company's presentation currency is the CAD. In this MD&A, all dollar amounts are expressed in CAD unless otherwise noted.

This MD&A contains non-IFRS measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "*Non-IFRS Measurements*", "*Abbreviations*" and "*Advisories*" sections at the end of this MD&A for further information.

Additional information relating to Bengal, including Bengal's audited March 31, 2019 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended December 31, 2019 may be referred to as "third quarter of fiscal 2020", "Q3 fiscal 2020", "Q3 FY 2020", "current quarter", and "the quarter". The comparative three months ended December 31, 2018 may be referred to as "third quarter of fiscal 2019", "Q3 fiscal 2019" and Q3 FY 2019. The nine months ended December 31, 2019 may be referred to as "nine months ended Q3 fiscal 2020", "YTD Q3 fiscal 2020" and YTD Q3 FY 2020". The comparative nine months ended December 31, 2018 may be referred to as "nine months ended Q3 fiscal 2019", "YTD Q3 fiscal 2019" and "YTD Q3 FY 2019.

THIRD QUARTER FISCAL 2020 SUMMARY

Financial Summary:

- **Sales Revenue** –Crude oil sales revenue was $2.4 million in the third quarter of fiscal 2020, which is 20% higher than the $2.0 million recorded in Q3 fiscal 2019. Higher sales volume in Q3 fiscal 2020 compared to Q3 fiscal 2019 was the main driver for the improved revenue performance despite a lower weighted average US Brent price.
- **Hedging** – The Company's Credit Facility (as defined herein) requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. During the current quarter, forward fixed-price contracts were placed on 50% of Q3 fiscal 2021 estimated production for October 2020 at US$59.27/bbl, November 2020 at US$58.95/bbl and December 2020 at US$58.63/bbl.
- **Cash from Operations** – Bengal generated cash from operations of $0.3 million during Q3 fiscal 2020 compared to $0.4 million of cash from operations in Q3 fiscal 2019. Cash flow generated from operations for the nine months ended Q3 fiscal 2020 was $1.1 million compared to $2.1 million in the nine months ended Q3 fiscal 2019. The primary reason for the lower cash from operations in Q3 fiscal 2020 is due to lower sales volumes and lower weighted average US Brent pricing.
- **Net Income** – Bengal reported net income of $0.6 million for the current quarter compared to net income of $0.9 million in the third quarter of fiscal 2019. Higher sales volume and the disposition of the drilling rig which was previously written off contributed to the positive quarterly net income in Q3 fiscal 2020. Net income for the current quarter is lower as compared to Q3 fiscal 2019 due to a substantial reduction in the value of the unrealized gain on financial instruments.
- **Credit Facility Extension** – On November 5, 2019, Westpac Institutional Bank ("Westpac") and the Company executed an agreement to extend the maturity date of the Company's bank debt of US$12.5 million to October 31, 2020.
- **Disposition** – On November 25, 2019 the Company entered into an agreement to sell its drilling rig to a third party for AUS$250,000. Payment was received on December 24, 2019. The drilling rig was purchased by the Company in 2012 but had not been part of its operating strategy since 2014.

Operational Summary:

- **Production Volumes** – The Company's light crude oil production in the current quarter was 25,758 bbls, which is a 7% decline from the 27,593 bbls produced in the third quarter of fiscal 2019. The current quarter production averaged 280 bbls/d compared to 300 bbls/d produced in the third quarter of fiscal 2019. The decline in production is a result of natural decline rate.
- **Capital Expenditures** – Bengal incurred $0.3 million in capital expenditures during Q3 fiscal 2020. This investment went towards the planning and evaluation of the Cuisinier production.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

Bengal's producing and non-producing assets are situated in Australia's Cooper Basin, a region featuring large accumulations of very light and high quality crude oil and natural gas. The Company's core Australian assets, ATP 934 Barrolka, Cuisinier, Tookoonooka, and four recently acquired petroleum licenses are situated within an area of the Cooper Basin that is well served with production infrastructure and take-away capacity for produced crude oil and natural gas. Still in early stages in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal and economic environment in which to operate, and a favourable royalty regime for oil and gas production.

Under the State of Queensland Regulatory process, ATPs (Authority to Prospect) are granted by the State generally for a period of twelve years with one third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a PCA (Potential Commercial Area). PCAs have a life span of five to fifteen years. If a discovery of oil or gas is made, an application for a PL (Petroleum Lease) is made to allow for production. PLs are granted for up to a thirty-year term. Bengal now has two PLs in the Cuisinier field, PL 303 and PL 1028. This is in addition to the four PLs acquired in Q2 FY 2020.

AUSTRALIA – Cooper Basin, Queensland

PL 303 and PL 1028 Cuisinier (controlling permit ATP 752) (30.357% WI)

The Cuisinier 29 well is on production from the newly discovered DC-50 zone. After expected initial decline rates the well has stabilized at approximately 110 bbls/d, (30 bbls/d net).

Planning and drilling location selection is underway for the next multi-well development and appraisal drilling campaign which is expected to commence late in Q4 of calendar 2020.

A pilot reservoir pressure maintenance scheme is planned to commence injection during Q2 of calendar 2020. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier 24 well. The broad nature of the Cuisinier structure combined with variable flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to increase production in up to four offsetting wells. In addition, the program will also complement future water flood expansion phases currently in the initial planning stages.

Wompi Block (controlling permit ATP 752) (38.08% WI)

The Company and its joint venture ("Joint Venture") partners are planning to conduct an extended production test on the Nubba gas discovery well. Initially planned for Q4 calendar 2019, the project is now delayed until there is certainty over a tie in point that can be accessed at a reasonable connection cost. Plans to tie in the well are subject to commercial flow rates and gas reserves being achieved.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. In order to mitigate both financial and development risk, Bengal has done extensive state-of-the-art geophysical work that has not been widely applied in Australia and which gives a higher degree of confidence in the block and focuses on the most likely prospects.

Discussions are ongoing with third parties who may have an interest in farming-in on a selective portion of this block, supporting the next phase of exploration and thereby further de-risking the natural gas potential of the permit.

PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

As announced in the Bengal press release of September 12, 2019, the Company has executed a binding sales and purchase agreement to acquire a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market (collectively, the "Assets"). These non-productive PLs are highly compatible with and in close proximity to ATP 934. The Company has obtained ownership of the respective PLs in Q2 FY 2020 subject to routine regulatory approvals. Bengal continues to integrate subsurface data from the PLs to enhance the Company's understanding of ATP 934 and to finalize the selection of exploration and appraisal drilling locations.

Included in this program is an oil-zone completion in a cased well, which recovered 588 bbls/d of light crude oil, based on a 105-minute drill stem test period when it was drilled in 2007. Upon completion of a successful test, this well is expected to be immediately equipped for production and the oil sold into the regional market. The Company is in discussions with potential industry and financial partners to fund this activity.

The 100% ownership of these Assets presents an appraisal and development opportunity that will be operated by the Company and is seen to be not only complementary to our proven producing, non-operated Cuisinier asset, but also as a key stepping stone for Bengal's natural gas platform upon which future exploration growth through ATP 934 can be undertaken.

OPERATING SUMMARY

($000s except per share, %, volumes and Operating netback amounts)		Three months ended December 31 2019		Three months ended December 31 2018		Nine months ended December 31 2019		Nine months ended December 31 2018
Oil revenue	$	2,425	$	2,014	$	6,963	$	8,544
Operating netback[1]	$	1,537	$	622	$	4,298	$	3,836
Cash flow from operations	$	259	$	434	$	1,102	$	2,056
Funds from (used in) operations[2]	$	599	$	(247)	$	1,310	$	1,378
Per share ($) (basic and diluted)	$	0.01	$	0.00	$	0.01	$	0.01
Net income (loss)	$	556	$	883	$	(700)	$	(331)
Per share ($) (basic and diluted)	$	0.01	$	0.01	$	(0.01)	$	0.00
Adjusted net income (loss)[3]	$	294	$	(649)	$	(14)	$	128
Per share ($) (basic and diluted)	$	0.00	$	(0.01)	$	(0.00)	$	0.00
Capital expenditures	$	346	$	298	$	2,103	$	1,873
Oil production volumes (bbls/d)		280		300		288		303
Operating netback[1]($/bbl)	$	59.68	$	22.54	$	54.32	$	45.99

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating netback per bbl is calculated by dividing revenue (including realized gain (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found on page 7.

(2) Funds from operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year-to-date. Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 18.

(3) Adjusted net income (loss) and adjusted net income (loss) per share are non-IFRS measures. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 19.

(4) The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

RESULTS OF OPERATIONS

Production	Three months ended December 31 2019	Three months ended December 31 2018	Nine months ended December 31 2019	Nine months ended December 31 2018
Oil production (bbls/d)	280	300	288	303
Oil production (bbls)	25,758	27,593	79,113	83,401

Revenue/Pricing

The following table outlines the oil lifting from bills of lading, pipeline oil estimates, applicable prices and oil sales reflected in the Company's financials:

		Three months ended December 31		Nine months ended December 31	
		2019	2018	2019	2018
	Oil lifting				
	Volume (000s bbls)	29.0	26.2	77.9	92.5
	Weighted average price (US$/bbl)	67.83	70.61	67.78	76.08
A.	Sales ($000's)	2,537	2,437	7,041	9,629
	Pipeline oil				
	Volume (000s bbls), change	(3.3)	1.4	1.1	(9.1)
	Price (US$/bbl), change	6.57	(23.99)	(9.42)	(10.05)
B.	Net sales ($000's)	(112)	(423)	(78)	(1,085)
A.+B.	Total oil sales ($000s)	2,425	2,014	6,963	8,544

The price received for Bengal's Australian oil sales is benchmarked on US Brent for the month in which the bill of lading occurs, plus a realized premium due to oil quality differences. Pipeline oil is the term used to describe oil moving along the pipeline from the wellhead to the port that has been legally transferred to the buyer but not priced and waiting to be sold. Lifting occurs when the oil is moved from the port to the ship.

The improved quarter over quarter revenue performance is due to a higher generated oil lifting revenue and higher pipeline oil valuation. Although the weighted average US Brent price for the oil lifting was lower in the current quarter (US Brent $67.83) as compared to Q3 2019 (US Brent $70.61), lifting volumes in the quarter were considerably higher at 29.0 k bbls as compared to 26.2 k bbls in Q3 fiscal 2019. This resulted in oil lifting revenue of $2.5 million in the current quarter as compared to $2.4 million in Q3 fiscal 2019. During the current quarter, the value of the pipeline oil decreased by only $0.1 million due to a combination of a decline in oil pipeline volume of 3,319 bbls (20,836 bbls at the beginning of the quarter down to 17,517 at the end of the quarter) and an increase in pipeline oil valuation of US$6.57/bbl. When oil lifting sales are adjusted for the change in value of the pipeline oil for the current quarter of $0.1 million, Bengal's total oil sales are $2.4 million for the current quarter as compared to $2.0 million for Q3 fiscal 2019.

The following table outlines average benchmark prices:

	Three months ended December 31		Nine months ended December 31	
	2019	2018	2019	2018
Brent oil ($/bbl)	83.70	89.49	86.12	94.69
Brent oil (US$/bbl)	63.41	67.71	64.75	72.48
Number of CAD$ for 1 AUS$	0.90	0.95	0.91	0.96
Number of CAD$ for 1 US$	1.32	1.32	1.33	1.31

($000s)

Operating Netbacks

	Three months ended December 31		Nine months ended December 31	
	2019	**2018**	**2019**	**2018**
Oil sales	2,425	2,014	6,963	8,544
Realized gain (loss) on financial instruments	(82)	(301)	265	(1,146)
Royalties	(191)	120	57	511
Operating expenses	997	971	2,873	3,051
Operating netback	1,537	622	4,298	3,836
($/bbl)				
Oil sales	94.15	72.99	88.01	102.44
Realized gain (loss) on financial instruments	(3.18)	(10.91)	3.35	(13.74)
Royalties	(7.42)	4.35	0.72	6.13
Operating expenses	38.71	35.19	36.32	36.58
Operating netback	59.68	22.54	54.32	45.99

Operating netbacks in Q3 fiscal 2020 were $1.5 million or $59.68/bbl compared to Q3 fiscal 2019 at $0.6 million or $22.54/bbl. For the nine months ended Q3 fiscal 2020, operating netback was $4.3 million or $54.32/bbl. This compares to $3.8 million or $45.99/bbl for the nine months ended Q3 fiscal 2019. Operating expenses for the current quarter were $38.71/bbl as compared to $35.19/bbl for Q3 fiscal 2019. See "*Operating Expenses*" for further explanation. Bengal had a realized loss on financial instruments of $0.1 million due to the approximate US$54.20/bbl hedges throughout the three months ended Q3 fiscal 2020. Royalty rates came in at (8)% of oil sales for Q3 fiscal 2020 or $(7.42)/bbl as compared to 6% of oil sales or $4.35/bbl for Q3 fiscal 2019. For the nine months ended Q3 fiscal 2020, royalties were 1% of sales as compared to 6% for nine months ended Q3 fiscal 2019.

Risk Management Activities

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia's Cooper Basin. It is a requirement under Bengal's Credit Facility to hedge 50% of its annual production.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its crude oil financial contracts on the statement of financial position at each reporting period, with the change in fair value being classified as unrealized gains and losses in the consolidated statement of income (loss).

As at December 31, 2019, the Company has the following derivative contracts:

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
January 1, 2020 – March 31, 2020	Oil - swap	5,000	63.74	63.74

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(45)	-	(45)
Non-current fair value of financial instruments	-	-	-
	(45)	-	(45)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
April 1, 2020 – April 30, 2020	Oil - swap	5,000	59.49	59.49

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(34)	-	(34)
Non-current fair value of financial instruments	-	-	-
	(34)	-	(34)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
May 1, 2020 – May 31, 2020	Oil - swap	5,000	59.27	59.27

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(32)	-	(32)
Non-current fair value of financial instruments	-	-	-
	(32)	-	(32)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
June 1, 2020 – June 30, 2020	Oil - swap	5,000	59.08	59.08

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(29)	-	(29)
Non-current fair value of financial instruments	-	-	-
	(29)	-	(29)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
July 1, 2020 – July 31, 2020	Oil - swap	5,000	56.64	56.64

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(42)	-	(42)
Non-current fair value of financial instruments	-	-	-
	(42)	-	(42)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
August 1, 2020 – August 31, 2020	Oil - swap	5,000	56.46	56.46

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(40)	-	(40)
Non-current fair value of financial instruments	-	-	-
	(40)	-	(40)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
September 1, 2020 – September 30, 2020	Oil - swap	5,000	56.32	56.32

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(39)	-	(39)
Non-current fair value of financial instruments	-	-	-
	(39)	-	(39)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
October 1, 2020 – October 31, 2020	Oil - swap	4,200	59.27	59.27

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
November 1, 2020 – November 30, 2020	Oil - swap	4,200	58.95	58.95

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
December 1, 2020 – December 31, 2020	Oil - swap	4,200	58.63	58.63

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Total			
($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(303)	-	(303)
Non-current fair value of financial instruments	-	-	-
	(303)	-	(303)

The fair value of the financial contracts outstanding as at December 31, 2019 is $(0.3) million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period, having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the nine months ended Q3 fiscal 2020, the derivative commodity contracts resulted in a realized gain of $0.3 million (December 31, 2018 – loss of $1.1 million) and an unrealized loss of $0.5 million (December 31, 2018 – gain of $1.8 million).

Royalties

Royalties	Three months ended December 31		Nine months ended December 31	
	2019	2018	2019	2018
Royalty expense ($000s)	(191)	120	57	511
$/bbl	(7.42)	4.35	0.72	6.13
% of revenue	(8)	6	1	6

The royalty rate is applied to gross revenues after deducting for allowable capital, transportation and operating costs.

Royalty rates came in at (8)% of oil sales for Q3 fiscal 2020 or $(7.42)/bbl as compared to 6% of oil sales or $4.35/bbl for Q3 fiscal 2019. The lower royalty expense per barrel in the current quarter is due to two factors 1) the Joint Venture operator over-accruing in previous quarters and taking the adjustment in Q3 fiscal 2020 worth approximately $0.09 million, and 2) the Company has taken its own over-accrual for royalty into income worth $0.3 million. The Company continues to expect that the realizable royalty rate will come in at 5-6% of revenue.

Operating Expenses

($000s) Operating expenses	Three months ended December 31 2019	2018	Nine months ended December 31 2019	2018
Production	263	168	541	538
Transportation	734	803	2,332	2,513
	997	971	2,873	3,051
Production - $/bbl	10.21	6.09	6.84	6.45
Transportation - $/bbl	28.50	29.10	29.48	30.13
	38.71	35.19	36.32	36.58

Total operating expense during the third quarter of fiscal 2020 was $1.0 million or $38.71/bbl. This compares to $1.0 million of operating expenses for the third quarter of fiscal 2019 or $35.19/bbl. Field operating expenses were higher in the current quarter due to incremental charges such as additional workover rig costs, fuel charges and administration charges. These charges added approximately $100k of additional costs as compared to Q3 fiscal 2019 and brought the field production costs per barrel to $10.21/bbl as compared to $6.09/bbl for Q3 fiscal 2019. For nine months ended Q3 fiscal 2020, total operating expenses were $2.9 million or $36.32/bbl. This compares favorably to Q3 fiscal 2019 of $3.0 million or $36.58/bbl.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended December 31 2019	2018	Nine months ended December 31 2019	2018
Total G&A	952	725	2,783	2,359
Capitalized G&A	261	39	439	265
Net G&A	691	686	2,344	2,094

Total G&A expense for Q3 fiscal 2020 was $1.0 million as compared to $0.7 million for Q3 fiscal 2019. Total G&A expenditures in the quarter were higher due to ongoing one time legal and consulting costs as a result of the Company's acquisition of the PLs and other strategic initiatives. Net G&A for Q3 fiscal 2020 and Q3 fiscal 2019 was $0.7 million, on par with Q3 fiscal 2019. The capitalized G&A value for Q3 fiscal 2020 is primarily due to legal and third-party costs associated with the acquisition of the PLs and other strategic initiatives. For nine months ended Q3 fiscal 2020 total G&A was $2.8 million as compared to $2.4 million for Q3 fiscal 2019, again primarily due to the one time cost related to the acquisition of the PLs.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended December 31 2019	2018	Nine months ended December 31 2019	2018
Expensed share-based compensation	5	13	22	56
Capitalized share-based compensation	-	1	1	7
	5	14	23	63

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date.

Depletion and Depreciation (DD&A)

($000s) **DD&A**	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
Petroleum and natural gas properties	373	352	1,155	1,076
Other assets	2	2	5	8
Right-of-use assets	11	-	35	-
	386	354	1,195	1,084
Petroleum and natural gas properties - $/bbl	14.48	12.76	14.60	12.90

The depletion rate per barrel for the current quarter of $14.48 is higher than the $12.76 for Q3 fiscal 2019 due to the significant capitalized development expenditure incurred in the previous two quarters. For the nine months ended Q3 fiscal 2020, total depletion expense was $1.2 million or $14.60/bbl as compares to $1.1 million or $12.90/bbl in Q3 fiscal 2019. The Company has adopted the new standard as per IFRS 16 requiring right-of-use asset disclosure. Further information on the adoption of this new standard can be found under the "*New Accounting Standards*" section at the end of the MD&A.

Impairment Expense

($000s) **Impairment expense**	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
Exploration and evaluation assets	-	(70)	10	885
Petroleum and natural gas properties	-	-	10	-
	-	(70)	20	885

During Q3 fiscal 2020, the Company did not take any impairment charges.

Finance Expense

($000s) **Finance expense**	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
Interest income	(1)	(1)	(2)	(9)
Accretion expense on decommissioning and restoration liability	9	10	26	30
Letter of credit charges	-	-	-	8
Interest on lease liability	4	-	11	-
Interest on credit facility	337	248	960	740
	349	257	995	769

Interest on the Credit Facility is calculated as US LIBOR plus a margin of 3.75%/3.95%, compared with US LIBOR plus 3.2% during fiscal 2019. The margins were increased in fiscal 2020 due to the Company's requirement to move the maturity dates of the facility as part of ongoing negotiation.

CAPITAL EXPENDITURES

($000s) **Capital expenditures**	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
Geological and geophysical	63	39	201	210
Drilling	(3)	(30)	145	830
Completions	25	289	1,344	833
Acquisition	261	-	413	-
	346	298	2,103	1,873
Exploration and evaluation expenditures	12	(42)	22	870
Development and production expenditures	334	340	2,081	1,003
	346	298	2,103	1,873

Capital expenditures of $0.3 million in Q3 fiscal 2020 (geological and geophysical, drilling and completions) relates to the completion of the five-well 2019 drilling program. Acquisition costs of $0.3 million relates to the acquisition of the new PLs.

CREDIT FACILITY

On May 29, 2019, the Company and Westpac entered into an amendment to its reserved based revolving credit facility (the "Credit Facility") that had principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment have transferred directly to the May 29, 2019 amendment. The Credit Facility requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. The interest rate under the Credit Facility remained unchanged at US LIBOR plus 3.75%.

On November 5, 2019, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to October 31, 2020. All previous terms and conditions remain the same except for the interest rate which moved from 3.75% to 3.95%.

Management continues to discuss with the lender the opportunity to lengthen the term of the current facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility.

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was in compliance with the stated covenants at December 31, 2019.

The table below indicates the payment schedule for the Credit Facility:

(US$000s)	
Credit Facility	
Fiscal year 2021	12,369

SHARE CAPITAL

Trading history	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
High ($)	0.10	0.12	0.13	0.18
Low ($)	0.05	0.09	0.05	0.09
Close ($)	0.08	0.09	0.08	0.09
Volume (000s)	1,418	2,863	3,179	7,600
Shares outstanding (000s)	102,267	102,267	102,267	102,267
Weighted average shares outstanding (000s) - basic and diluted	102,267	102,267	102,267	102,267

At February 11, 2020, there were 102,266,694 common shares issued and outstanding, together with 3,472,500 outstanding options.

LIQUIDITY RISK AND CAPITAL RESOURCES AND GOING CONCERN

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables, financial instruments, lease liability and the Credit Facility, amounting to $17.9 million at December 31, 2019 (March 31, 2019 - $19.1 million). At December 31, 2019, the Company had a working capital deficiency of $13.8 million, including cash and cash equivalents of $0.9 million and restricted cash of $0.1 million, compared to working capital of $6.3 million at December 31, 2018 and a working capital deficiency of $12.7 million at March 31, 2019. The working capital deficiencies are primarily a result of the reclassification of the bank debt of $16.2 million to current from long term. The Company has no available undrawn debt capacity under its Credit Facility.

The Company's ability to continue as a going concern is dependent upon its ability to raise additional financing to further explore its capital projects. While Management has secured financing in the past, there can be no assurance it will be able to do so in the future or that these sources of funding will be available for the Company. If Management is unable to obtain new funding, the Company may be unable to continue its operations, and amounts realized for assets might be less than amounts reflected in these financial statements and this could have a significant impact on the financial position of the Company, its financial performance and its cash flows.

The majority of the Company's oil sales are benchmarked on US Brent prices, which averaged US$64.75/bbl for the nine months ended Q3 fiscal 2020. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of lower crude prices, the Company is acting with its Joint Venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where practical and appropriate. The Company intends to use a combination of internally generated sources of cash and externally generated sources of cash, such as farm-outs and alternative financing sources to fund its exploration and development activities through fiscal 2020 and beyond.

COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company acquired an additional 21.43% working interest and received ministerial approval for the acquisition on August 11, 2015. In Q4 FY 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of AUS$0.2 million on certification by an independent competent person appointed by the buyer of not less than 25 billion ft^3 of proved reserves and AUS$0.8 million due upon the delivery of first commercial gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.

AFE commitments are reflected where the Company has agreed with Joint Venture partners to proceed with activities (e.g. onshore Australia, Barta Block Cuisinier PL 303). The costs of these activities are based on minimum work budgets included in bid documents and agreements among Joint Venture parties, and have not been provided for in the financial statements. Actual costs may vary from budget. See "*Liquidity Risk and Capital Resources and Going Concern*" above.

At December 31, 2019, the Company had the following capital work commitments:

Country and permit	**Work program**	**Obligation period ending**	**Estimated expenditure (net) (millions CAD$)** (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2021	12.9
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at December 31, 2019 at an exchange rate of AUS$1.00 = CAD$ 0.9128.

At December 31, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) **Contractual obligations October 2019 to November 2023**	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Office lease	621	155	312	154	-
Decommissioning and restoration	3,483	-	549	-	2,934
	4,104	155	861	154	2,934

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	**Dec 31 2019** **Q3 2020**	Sep 30 2019 Q2 2020	June 30 2019 Q1 2020	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019	Mar 31 2018 Q4 2018
Oil sales	2,425	2,576	1,962	2,667	2,014	3,315	3,215	2,783
Cash flow from operations	259	527	316	635	434	603	1,019	858
Funds from (used in) operations(1)	599	724	(13)	842	(247)	750	875	525
Per share – basic and diluted ($)	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01
Net income (loss)	556	(506)	(750)	(2,144)	883	(728)	(486)	(12,526)
Per share – basic and diluted ($)	0.01	(0.00)	(0.01)	(0.02)	0.01	(0.01)	0.00	(0.12)
Capital expenditures	346	477	1,280	2,473	298	1,274	301	939
Working capital (deficiency)	(13,823)	(14,120)	(13,964)	(12,740)	6,331	(3,353)	(2,915)	3,385
Total assets	41,391	40,849	40,373	42,489	44,291	43,547	44,867	45,714
Shares outstanding (000s)	102,267	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	280	333	249	281	300	292	318	334
Operating netback(1) ($/bbl)	59.68	53.78	49.01	76.82	22.54	59.58	55.69	42.66

(1) See "*Non-IFRS Measurements*" on page 18 of this MD&A.

Oil sales and production over the last eight quarters peaked during the second quarter of fiscal 2018 (calendar Q3 2017) as all wells from the Company's 2014 and 2016 drilling campaign were on stream. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since the peak in the second quarter of fiscal 2018. A significant decline in US Brent prices during Q3 fiscal 2019 was responsible for the low oil sales and funds from operations. The Company invested in a five well drilling program in Q4 fiscal 2019 that was completed in Q1 fiscal 2020. The increase in oil volumes in Q2 fiscal 2020 to 333 bbls/d was the result of the 5 well drilling program.

DISCLOSURE CONTROLS & PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and includes controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and Chief Financial Officer have individually signed certifications to this effect.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision 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. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at December 31, 2019 due to the material weaknesses noted below.

No changes in internal controls over financial reporting were identified during the period that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

While Bengal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design and operating effectiveness assessment, certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general and administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs; and
- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues and for tax planning, tax provision and compilation of corporate tax returns.

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board of Directors do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates, which are reviewed on an ongoing basis. A full discussion of the Company's critical judgments and accounting estimates is included in its 2019 annual Management's Discussion and Analysis dated June 20, 2019.

NEW ACCOUNTING STANDARDS

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease.

On adoption of IFRS 16, the Company's lease liability related to contracts classified as leases are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease liability at adoption was approximately 6.0%. The right-of-use asset and lease liability recognized relate to the Company's head office lease in Calgary.

Upon the adoption of IFRS 16, the Company adopted the following significant accounting policy effective April 1, 2019:

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liability using the effective interest rate method and payments are applied against the lease liability.

Key areas where management has made judgments, estimates and assumptions related to the application of IFRS 16 include:

- The incremental borrowing rate is based on judgments including economic environment, term, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liability and the resulting interest expense and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

IFRS 3

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. The changes clarify the minimum requirements to be a business, assess whether an acquired process is substantive, narrow the definition of outputs and implement an optional concentration test. The amendments to IFRS 3 are effective for annual reporting periods beginning on or after 1 January 2020 and apply prospectively and early application is permitted. Effective July 1, 2019, the Company applied the amendment.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, operating netbacks per share, funds from operations, funds from operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Operating netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Operating netback per barrel equals operating netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed Adjusted net income is a non-IFRS measure, which should not be considered an alternative to “Net income (loss)” as presented in the consolidated statement of income (loss) and comprehensive income (loss), and is presented in the Company’s financial reports to assist management and investors in analyzing financial performance net of gains and losses outside of management’s immediate control. Adjusted net income equals net income (loss) less unrealized gain (losses) on foreign exchange and unrealized gain (losses) on financial instruments plus non-cash impairment of non-current assets. Adjusted net income per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

Management believes the presentation of the non-IFRS measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

The following table reconciles cash from operations to funds from operations, which is used in this MD&A:

($000s)	**Three months ended December 31**		**Nine months ended December 31**	
	2019	**2018**	**2019**	**2018**
Cash from operating activities	259	434	1,102	2,056
Changes in non-cash working capital	340	(681)	208	(678)
Funds from (used in) operations	599	(247)	1,310	1,378

The following table reconciles net income (loss) to adjusted net income (loss), which is used in this MD&A:

($000s)	Three months ended December 31		Nine months ended December 31	
	2019	2018	2019	2018
Net income (loss)	556	883	(700)	(331)
Unrealized loss (gain) on financial instruments	357	(1,845)	470	(1,826)
Unrealized foreign exchange (gain) loss	(619)	383	196	1,400
Non-cash impairment of non-current assets	-	(70)	20	885
Adjusted net income (loss)	294	(649)	(14)	128

ABBREVIATIONS

The following abbreviations used in this MD&A have the meanings set forth below:

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
$/bbl	-	dollars per barrel
ft^3	-	cubic feet
FY	-	fiscal year
k	-	thousand
km	-	kilometres
km^2	-	square kilometres
Q1	-	three months ended June 30
Q2	-	three months ended September 30
Q3	-	three months ended December 31
Q4	-	three months ended March 31
WI	-	working interest
YTD	-	year to date

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated July 2, 2019 filed on SEDAR at www.sedar.com.

Bengal monitors and updates its cash projection models on a regular basis, which assists in the timing decision of capital expenditures. Farm outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

An investment in the shares of the Company should be considered speculative due to the nature of the Company's involvement in the exploration for and the acquisition, development and production of oil and natural gas in foreign countries, and its current stage of development. An investor should consider carefully the risk factors set out in the annual information form and consider all other information contained herein and in the Company's other public filings before making an investment decision. Additional risks and uncertainties not currently known to the management of the Company may also have an adverse effect on Bengal's business and the information set out in the annual information form does not purport to be an exhaustive summary of the risks affecting Bengal.

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 2000, 715 5th Avenue SW., Calgary, Alberta T2P 2X6, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

Forward-looking Statements - *Certain statements contained within this MD&A constitute forward-looking statements or information ("forward-looking statements") as defined by applicable securities laws. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "would," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. The projections, estimates and beliefs contained in such forward-looking statements are based on management's estimates, opinions, and assumptions at the time the statements were made, including assumptions relating to: the impact of economic conditions in North America and Australia and globally; industry conditions; changes in laws and regulations including, without limitation, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the availability of qualified operating or management personnel; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and fluctuations in market valuations of companies with respect to announced transactions and the final valuations thereof; results of exploration and testing activities; and the ability to obtain required approvals and extensions from regulatory authorities.*
In particular, this MD&A contains forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Bengal's drilling campaigns and the timing and anticipated results thereof;*
- *The timing of the next multi-well development and appraisal drilling campaign on PL 303;*
- *The anticipated timing and results of a pressure maintenance scheme and the injection of produced formation water in the Cooper Basin on ATP 752;*
- *The timing and nature of a production test at the Wompi Block including subsequent actions that may be taken depending on the results thereof;*
- *The potential farm-in with third parties on ATP 934;*
- *The receipt of regulatory approval in respect of the Assets, the anticipated results and characteristics of the Assets and development plans in respect therewith;*
- *The anticipated future exploration growth opportunities on ATP 934 through the ownership of the Assets;*
- *Anticipated funding requirements and sources for the Company's development program;*
- *Payments made in fiscal 2021 under the Credit Facilities;*
- *Discussions with the Company's lenders, the results thereof and the impact on the Company if it is unable to negotiate an amendment and deferral of principal payment on the Credit Facilities;*
- *The continued monitoring of trends in commodity prices and intention to use a combination of both internally generated sources of cash and externally generated sources of cash to fund future exploration and development activities; and*
- *Expected future realizable royalty rates;*

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause Bengal's actual results, performance or achievement to differ materially from those expectations expressed in, or implied by, these forward-looking statements, including but not limited to, risks associated with:

- *Fluctuations in commodity prices, foreign exchange or interest rates;*
- *Changes in the demand for or supply of Bengal's products;*
- *Liabilities inherent in oil and natural gas operations;*
- *The failure to obtain required regulatory approvals or extensions;*
- *The failure to satisfy the conditions under farm-in and joint venture agreements;*
- *The failure to secure required equipment and personnel;*
- *Changes in general global economic conditions including, without limitations, the economic conditions in North America and Australia;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Increased competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *The availability of qualified operating or management personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Inability to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Bengal's development and exploration opportunities;*
- *The results of exploration and development drilling and related activities;*
- *Changes in laws and regulations including, without limitation, the adoption of new environmental, royalty and tax laws and regulations and changes in how they are interpreted and enforced;*
- *The ability to access sufficient capital from internal and external sources; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, which the resources and reserves described, can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking *statements contained in this MD&A are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website (www.sedar.com) and at Bengal's website (www.bengalenergy.ca).*

Disclosure of Oil and Gas Information

This document discloses unbooked drilling locations. Unbooked locations are internal estimates based on the Company'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 or resources. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources 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.

Test Rates

References in this MD&A to production test rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results are historical and not indicative of expected production.

Internal Estimates

Certain information contained herein is based on estimated values the Company believes to be reasonable and are subject to the same limitations as discussed under "Forward-looking Statements" above.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Dr. Brian J. Moss
Robert D. Steele
Ian J. Towers (Chairman)
W. B. (Bill) Wheeler

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

James B. Howe (Chairman)
Robert D. Steele
W. B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Dr. Brian J. Moss
Ian J. Towers

GOVERNANCE AND COMPENSATION COMMITTEE

Peter D. Gaffney
Dr. Brian J. Moss
Robert D. Steele (Chairman)
Ian J. Towers

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Matthew Moorman, Chief Financial Officer
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG

Interim Consolidated Financial Statements

(Unaudited)

Three and Nine Months Ended
December 31, 2019 and 2018

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at	Notes	December 31 2019	March 31 2019
Assets			
Current assets:			
Cash and cash equivalents		$ 880	$ 2,891
Restricted cash		140	140
Trade and other receivables	4	2,737	2,972
Prepaid expenses and deposits		142	136
Fair value of financial instruments	16	-	177
		3,899	6,316
Exploration and evaluation assets	5	9,370	9,711
Property, plant and equipment	6	28,122	26,462
Total assets		$ 41,391	$ 42,489
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	7	$ 1,133	$ 2,574
Fair value of financial instruments	16	303	-
Current portion of credit facility	8	16,238	16,482
Current portion of lease liability	9	48	-
		17,722	19,056
Decommissioning and restoration liability	10	3,483	1,977
Lease liability	9	168	-
		21,373	21,033
Shareholders' equity:			
Share capital	11	98,100	98,100
Contributed surplus		7,855	7,832
Accumulated other comprehensive loss		(765)	(4)
Deficit		(85,172)	(84,472)
		20,018	21,456
Total liabilities and shareholders' equity		$ 41,391	$ 42,489

Going concern (Note 2)

Commitments (Note 18)

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

	Notes	Three months ended December 31 2019	Three months ended December 31 2018	Nine months ended December 31 2019	Nine months ended December 31 2018
Revenue					
Oil sales	13	$ 2,425	$ 2,014	$ 6,963	$ 8,544
Royalties		191	(120)	(57)	(511)
		2,616	1,894	6,906	8,033
Realized gain (loss) on financial instruments	16	(82)	(301)	265	(1,146)
Unrealized gain (loss) on financial instruments	16	(357)	1,845	(470)	1,826
		2,177	3,438	6,701	8,713
Expenses					
General and administrative		691	686	2,344	2,094
Operating		997	971	2,873	3,051
Depletion and depreciation	6	386	354	1,195	1,084
Impairment	5,6	-	(70)	20	885
Share-based compensation		5	13	22	56
Foreign exchange gain (loss)		(586)	344	173	1,105
		1,493	2,298	6,627	8,275
Other (income) expense					
Gain on sale		(221)	-	(221)	-
Finance expense	15	349	257	995	769
Net income (loss)		556	883	(700)	(331)
Exchange differences on translation of foreign operations		397	729	(761)	(694)
Comprehensive income (loss)		$ 953	$ 1,612	$ (1,461)	$ (1,025)
Income (loss) per share - basic & diluted	14	$ 0.01	$ 0.01	(0.01)	$ 0.00
Weighted average shares outstanding (000s) – basic and diluted	14	102,267	102,267	102,267	102,267

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

(unaudited)

For the nine months ended December 31	2019	2018
Share capital		
Balance at beginning and end of period	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of period	7,832	7,755
Share-based compensation – expensed	22	56
Share-based compensation – capitalized	1	7
Balance at end of period	7,855	7,818
Accumulated other comprehensive (loss) income		
Balance at beginning of period	(4)	1,034
Exchange differences translation of foreign operations	(761)	(694)
Balance at end of period	(765)	340
Deficit		
Balance at beginning of period	(84,472)	(81,997)
Net loss	(700)	(331)
Balance at end of period	(85,172)	(82,328)
Total shareholders' equity	$ 20,018	$ 23,930

See accompanying notes to the interim consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

	Notes	Three months ended December 31 2019	Three months ended December 31 2018	Nine months ended December 31 2019	Nine months ended December 31 2018
Operating activities:					
Net income (loss)		$ 556	$ 883	$ (700)	$ (331)
Add (deduct) non-cash items					
Depletion and amortization		386	354	1,195	1,084
Gain on sale		(221)	-	(221)	-
Accretion on decommissioning and restoration liability		9	10	26	30
Accretion on credit facility		123	25	261	80
Share-based compensation		5	13	22	56
Interest on lease liability		3	-	10	-
Lease incentive		-	-	31	-
Impairment		-	(70)	20	885
Unrealized loss (gain) on financial Instruments		357	(1,845)	470	(1,826)
Unrealized foreign exchange (gain) loss		(619)	383	196	1,400
Funds from (used in) operations		599	(247)	1,310	1,378
Change in non-cash working capital	17	(340)	681	(208)	678
Net cash from operating activities		259	434	1,102	2,056
Investing activities:					
Exploration and evaluation expenditures	5	(12)	42	(22)	(870)
Petroleum and natural gas property expenditures	6	(334)	(340)	(2,081)	(1,003)
Proceeds on sale		221	-	221	-
Change in non-cash working capital	17	(401)	(250)	(1,017)	280
Net cash used in investing activities		(526)	(548)	(2,899)	(1,593)
Financing activities:					
Repayment of credit facility		-	(176)	-	(176)
Lease payments		(15)	-	(45)	-
Facility extension fees		(66)	-	(99)	-
Change in non-cash working capital	17	(12)	(227)	(2)	(36)
Net cash used in financing activities		(93)	(403)	(146)	(212)
Net (decrease) increase in cash and cash equivalents		(360)	(517)	(1,943)	251
Cash and cash equivalents, beginning of period		1,221	4,415	2,891	3,904
Impact of foreign exchange on cash and cash equivalents		19	131	(68)	(126)
Cash and cash equivalents, end of period		$ 880	$ 4,029	$ 880	$ 4,029

See accompanying notes to the interim consolidated financial statements.

1. REPORTING ENTITY

Bengal Energy Ltd. (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration, development and production of oil and gas reserves in Australia. The interim consolidated financial statements (the "financial statements") of the Company are comprised of the Company and its wholly-owned subsidiaries including Bengal Energy Australia (Pty) Ltd. and Bengal Energy International Inc., which are incorporated in Australia and Canada respectively. The Company conducts many of its activities jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

The Company has its registered office at 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1 and its head and principal office at 2000, 715 - 5th Ave SW, Calgary, Alberta T2P 2X6.

2. BASIS OF PREPARATION AND GOING CONCERN

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". These interim consolidated financial statements do not include all of the information required for full annual financial statements.

These financial statements are stated in Canadian dollars and have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended March 31, 2019 except as specified in Note 3 below. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended March 31, 2019.

These financial statements were approved and authorized for issuance by the Board of Directors on February 11, 2020.

The Company's presentation currency is Canadian dollars. The functional currency of the Canadian parent entity is Canadian dollars; the functional currency of the Australian subsidiary is Australian dollars.

Going concern

These financial statements have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

At December 31, 2019, the Company had a working capital deficiency of $13.8 million. The Company has no available undrawn debt capacity under its credit facility which will expire on October 31, 2020.

The Company's ability to continue as a going concern is dependent upon the ability to renew the current credit facility or to raise additional financing to continue with its capital projects. There can be no assurances that the facility will be renewed or additional sources of funding will be available for the Company. These matters cause material uncertainty which may cast significant doubt on the Company's ability to continue as a going concern.

These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern assumption were not appropriate, adjustments would be necessary in the carrying value of the Company's assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Adoption of IFRS 16, Leases

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 6), with a corresponding increase to lease liability (Note 9). There was an adjustment of $ 31,232 to the right-of-use assets for lease incentives previously received.

On adoption of IFRS 16, the Company's lease liability related to contracts classified as leases are measured at the discounted present value of the remaining minimum lease payments, excluding short-term and low-value leases. The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations. The weighted average incremental borrowing rate used to determine the lease liability at adoption was approximately 6.0%. The right-of-use asset and lease liability recognized relate to the Company's head office lease in Calgary.

Upon the adoption of IFRS 16, the Company adopted the following significant accounting policy effective April 1, 2019:

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that are not paid at that date. At the commencement date, a corresponding right-of-use asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liability using the effective interest rate method and payments are applied against the lease liability.

Key areas where management has made judgments, estimates and assumptions related to the application of IFRS 16 include:

- The incremental borrowing rate is based on judgments including economic environment, term, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liability and the resulting interest expense and depreciation expense, may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

IFRS 3 Amendment

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. The changes clarify the minimum requirements to be a business, assess whether an acquired process is substantive, narrow the definition of outputs and implement an optional concentration test. The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020, and apply prospectively and early application is permitted. Effective April 1, 2019, the Company applied the amendment.

4. TRADE AND OTHER RECEIVABLES

Bengal's trade and other receivables are exposed to the risk of financial loss if a counterparty to a financial instrument fails to meet its contractual obligations. The Company's trade and other receivables include cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers.

The Company's trade and other receivables consist of:

($000s)	December 31, 2019	March 31, 2019
Due from joint venture partners	2,692	2,928
Other receivables	45	44
	2,737	2,972

In Australia, production is purchased by a buying group led by Santos Ltd., the operator of Bengal's production. Bengal has a crude oil sales and purchase agreement with this buying group and has not experienced any collection problems to date.

Cash calls paid to Santos Ltd., Bengal's Australian joint interest partner, are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint interest receivables by approving significant spending by partners prior to expenditure and only paying the cash call shortly before the funds are to be spent.

The Company had no accounts considered past due at December 31, 2019 (March 31, 2019 - $nil). Past due is considered greater than 90 days outstanding.

Management considers the credit risk of these instruments to be adequately mitigated by the credit rating of their holder; therefore, no allowance has been established.

5. EXPLORATION AND EVALUATION ASSETS ("E&E ASSETS")

($000s)	
Balance, April 1, 2018	10,102
Additions	930
Capitalized share-based compensation	4
Impairment	(894)
Exchange adjustments	(431)
Balance, March 31, 2019	9,711
Additions	22
Capitalized share-based compensation	-
Impairment	(10)
Exchange adjustments	(353)
Balance, December 31, 2019	9,370

A summary of E&E assets is shown in the table below:

($000s)	
ATP 732P – Tookoonooka	5,165
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,641
ATP 934 – Barrolka	1,905
Balance, March 31, 2019	9,711

($000s)	
ATP 732P – Tookoonooka	4,976
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,557
ATP 934 – Barrolka	1,837
Balance, December 31, 2019	9,370

Exploration and evaluation assets consist of the Company's exploration projects in Australia, which are pending the determination of proved or probable reserves. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling, and completion costs until the drilling of wells is complete and the results have been evaluated.

6. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

($000s)	**Petroleum and natural gas properties**	**Other assets**	**Right-of-use assets**	**Total**
Cost:				
Balance, April 1, 2018	44,236	344	-	44,580
Additions	3,416	-	-	3,416
Capitalized share-based compensation	4	-	-	4
Change in decommissioning and restoration liability	448	-	-	448
Exchange adjustments	(2,737)	-	-	(2,737)
Balance, March 31, 2019	45,367	344	-	45,711
Additions	1,668	-	-	1,668
Acquisition	1,950	-	-	1,950
Right-of-use assets	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Exchange adjustments	(2,366)	-	-	(2,366)
Balance, December 31, 2019	46,620	344	219	47,183

($000s)	**Petroleum and natural gas properties**	**Other assets**	**Right-of-use assets**	**Total**
Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2018	17,172	301	-	17,473
Depletion and depreciation	1,446	11	-	1,457
Impairment	1,897	-	-	1,897
Exchange adjustments	(1,578)	-	-	(1,578)
Balance, March 31, 2019	18,937	312	-	19,249
Depletion and depreciation	1,155	5	35	1,195
Impairment	10	-	-	10
Exchange adjustments	(1,393)	-	-	(1,393)
Balance, December 31, 2019	18,709	317	35	19,061
($000s)				
Net carrying amount:				
At December 31, 2019	27,911	27	184	28,122
At March 31, 2019	26,430	32	-	26,462

The Company recorded an impairment charge of $1.9 million during Q4 fiscal 2019 due to uneconomic drilling results.

The calculation of depletion for the three and nine months ended December 31, 2019 included $61.0 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2019 - $60.9 million).

During Q2 fiscal 2020, the Company acquired four Petroleum Leases (“PLs”), for nominal cash consideration. The associated decommissioning and restoration liability is valued at $1.54 million and acquisition costs of $0.4 million. All four PLs are located adjacent to the Company’s existing gas exploration block ATP 934 in the Cooper Basin.

The Company recognized a right-of-use asset and the corresponding lease liability (Note 9) related to the Company’s head office lease in Calgary. The right-of-use asset addition of $219,000 was net of a lease incentive of $31,000.

7. TRADE AND OTHER PAYABLES

($000s)	**December 31, 2019**	**March 31, 2019**
Trade payables	287	1,525
Accrued liabilities and other payables	846	1,049
	1,133	2,574

8. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(2,160)
	12,210
Facility extension fees	(227)
Unrealized foreign exchange loss	3,264
Accretion	1,235
Balance, March 31, 2019	16,482
Unrealized foreign exchange loss	(406)
Facility extension fees	(99)
Accretion	261
Balance, December 31, 2019	16,238

($000s)	**December 31, 2019**	**March 31, 2019**
Current portion	16,238	16,482
Non-current portion	-	-

On May 29, 2019, the Company and Westpac entered into an amendment to its reserved based revolving credit facility (the “Credit Facility”) that had principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment have transferred directly to the May 29, 2019 amendment. The Credit Facility requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. The interest rate under the Credit Facility remained unchanged at US LIBOR plus 3.75%.

On November 5, 2019, the Company and Westpac agreed to further delay the maturity date of the Credit Facility to October 31, 2020. All previous terms and conditions remain the same except for the interest rate which moved from 3.75% to 3.95%.

Management continues to discuss with the lender the opportunity to lengthen the term of the current facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. There would be an adverse impact on the Company's liquidity should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility.

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was in compliance with the stated covenants at December 31, 2019.

The table below indicates the current payment schedule for the Credit Facility:

(US$000s)	
Fiscal year 2020	12,369
	12,369

9. LEASE LIABILITY

The Company incurs lease payments related to the Company's head office lease in Calgary.

($000s)	
Balance, March 31, 2019	-
Lease liability for right-of-use assets	250
Interest	11
Payments	(45)
Balance, December 31, 2019	216
Current portion of lease liability	(48)
Non-current portion of lease liability	168

10. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2018	1,556
Change in estimate	168
Additions	280
Accretion	39
Exchange adjustments	(66)
Balance, March 31, 2019	1,977
Acquisition (Note 6)	1,538
Accretion	26
Exchange adjustments	(58)
Balance, December 31, 2019	3,483

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation-adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at December 31, 2019 is approximately $4.0 million (March 31, 2019 - $2.5 million) which will be incurred between 2022 and 2048. An inflation factor of 1.78% (March 31, 2019 – 1.78%) and a risk-free discount rate of 1.79% (March 31, 2019 – 1.79%) have been applied to the decommissioning liability at December 31, 2019.

11. SHARE CAPITAL

Authorized:

Unlimited number of common shares with no par value.

Unlimited number of preferred shares, of which none have been issued.

Issued:

The following provides a continuity of share capital:

($000s)	**Number of common shares**	**Amount**
Balance, April 1, 2018	68,177,796	94,151
Issued on exercise of rights offering	34,088,898	4,091
Share issue costs	-	(142)
Balance at March 31, 2019 and December 31, 2019	102,266,694	98,100

12. SHARE-BASED COMPENSATION

The Company has a share option plan for directors, officers and employees of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of up to five years and vest one-third after the first year and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

Effective with the option grant of July 30, 2015, performance criteria were introduced, which allow for the vesting of stock options contingent on meeting pre-established targets based on internal and external metrics.

Effective with the option grant on April 9, 2018, the exercise price of each option equals the weighted average market share price of the previous five days.

The Company accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss over the first year. The remaining two instalments are charged to profit or loss over two and three years respectively.

Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

A summary of stock option activity is presented below:

	Options	Weighted average exercise price $
Balance, March 31, 2019	4,102,500	0.12
Expired	(136,375)	0.12
Forfeited	(477,799)	0.12
Balance, December 31, 2019	3,488,326	0.12
Exercisable, December 31, 2019	1,918,730	0.11

13. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement ("COSPA agreement") with the joint venture operator. The Company recognizes revenue when it transfers control of the product to the joint venture operator, which is generally at the time the joint venture operator obtains legal title of the crude oil and when it is physically delivered to the pipeline at an estimated transaction price based on average US Brent price and is adjusted for quality and other factors specified in the COSPA agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the COSPA agreement is a variable price based on the benchmark US Brent commodity price index, and may be adjusted for quality, location, delivery method or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantity of crude oil transferred to the joint venture operator. The COSPA agreement has an initial term to March 31, 2022. Revenues are typically collected 60 days following delivery to Port Bonython.

14. PER SHARE AMOUNTS

Income (loss) per share is calculated based on net loss and the weighted-average number of common shares outstanding.

	Three months ended December 31		Nine months ended December 31	
	2019	2018	2019	2018
Net income (loss) for the period ($000s)	556	883	(700)	(331)
Weighted average number of Common shares – basic and diluted (000s)	102,267	102,267	102,267	102,267
Basic and diluted income (loss) per share	$0.01	$0.01	$(0.01)	$(0.00)

For the three and nine months ended December 31, 2019, there were 3,488,326 (2018 – 4,187,500) options considered anti-dilutive.

15. FINANCE EXPENSE

($000s)	Three months ended December 31 2019	2018	Nine months ended December 31 2019	2018
Interest income	(1)	(1)	(2)	(9)
Accretion on decommissioning and restoration liability	9	10	26	30
Letter of credit charges	-	-	-	8
Interest on lease liability	4	-	11	-
Interest on credit facility	337	248	960	740
	349	257	995	769

16. FINANCIAL RISK MANAGEMENT

Liquidity Risk and Going Concern

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables, financial instruments, lease liability and credit facility, amounting to $17.9 million at December 31, 2019 (March 31, 2019 - $19.1 million). At December 31, 2019, the Company had a working capital deficiency of $13.8 million, including cash and cash equivalents of $0.9 million and restricted cash of $0.1 million and a working capital deficiency of $12.7 million at March 31, 2019. The working capital deficiencies are primarily a result of the reclassification of the credit facility of $16.2 million to current from long term. The Company has no available undrawn debt capacity under its Westpac Credit Facility.

The current challenging economic climate may lead to adverse changes in cash flow, working capital levels or debt balances, which may also have a direct impact on the Company's results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

Foreign Currency Risk

Bengal receives U.S. dollars for Australian oil sales and incurs expenditures in Australian and Canadian currencies. The Company may enter into derivative foreign currency contracts in order to manage foreign currency exchange rate risk, but has not done so as at December 31, 2019.

The table below shows the Company's exposure to foreign currencies for its financial instruments at December 31, 2019:

($000s)

	CAD$	**AUS$**	**US$**	**Total**
Cash and short-term deposits	158	286	436	880
Restricted cash	140	-	-	140
Trade and other receivables	9	13	2,715	2,737
Fair value of financial instruments	-	-	(303)	(303)
Trade and other payables	(175)	(953)	(5)	(1,133)
Credit facility	-	-	(16,238)	(16,238)
Lease liability	(216)	-	-	(216)
	(84)	(654)	(13,395)	(14,133)

Exchange rates as at:	December 31 2019	March 31 2019
Number of CAD$ for 1 AUS$	0.91	0.95
Number of CAD$ for 1 US$	1.30	1.34

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the US Brent reference price, which currently trades at a premium to WTI.

At December 31, 2019, the following derivative contracts were outstanding and recorded at estimated fair value:

Time period	**Type of contract**	**Quantity Contracted (bbls)**	**Price floor US$/bbl**	**Price ceiling US$/bbl**
January 1, 2020 – March 31, 2020	Oil - swap	5,000	63.74	63.74

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(45)	-	(45)
Non-current fair value of financial instruments	-	-	-
	(45)	-	(45)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
April 1, 2020 – April 30, 2020	Oil - swap	5,000	59.49	59.49

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(34)	-	(34)
Non-current fair value of financial instruments	-	-	-
	(34)	-	(34)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
May 1, 2020 – May 31, 2020	Oil - swap	5,000	59.27	59.27

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(32)	-	(32)
Non-current fair value of financial instruments	-	-	-
	(32)	-	(32)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
June 1, 2020 – June 30, 2020	Oil - swap	5,000	59.08	59.08

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(29)	-	(29)
Non-current fair value of financial instruments	-	-	-
	(29)	-	(29)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
July 1, 2020 – July 31, 2020	Oil - swap	5,000	56.64	56.64

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(42)	-	(42)
Non-current fair value of financial instruments	-	-	-
	(42)	-	(42)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
August 1, 2020 – August 31, 2020	Oil - swap	5,000	56.46	56.46

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(40)	-	(40)
Non-current fair value of financial instruments	-	-	-
	(40)	-	(40)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
September 1, 2020 – September 30, 2020	Oil - swap	5,000	56.32	56.32

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(39)	-	(39)
Non-current fair value of financial instruments	-	-	-
	(39)	-	(39)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
October 1, 2020 – October 31, 2020	Oil - swap	4,200	59.27	59.27

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
November 1, 2020 – November 30, 2020	Oil - swap	4,200	58.95	58.95

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US$/bbl	Price ceiling US$/bbl
December 1, 2020 – December 31, 2020	Oil - swap	4,200	58.63	58.63

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(14)	-	(14)
Non-current fair value of financial instruments	-	-	-
	(14)	-	(14)

Total

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	(303)	-	(303)
Non-current fair value of financial instruments	-	-	-
	(303)	-	(303)

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$57,600 (CAD$75,000) decrease in the fair value of financial instruments at December 31, 2019, while a US$1.00 decrease would result in an increase of approximately US$57,600 (CAD$75,000) in the fair value of the instruments.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at December 31, 2019 as the funds are not invested in interest-bearing instruments. The Company's Credit Facility carries a floating interest rate based on quoted US LIBOR rates. The Company had no interest rate derivatives at December 31, 2019.

For the nine months ended December 31, 2019, a 1% increase in US LIBOR would increase interest expense by $123,200.

17. SUPPLEMENTAL CASH FLOW INFORMATION

($000s)

Change in non-cash working capital items

	Three months ended December 31		Nine months ended December 31	
	2019	**2018**	**2019**	**2018**
Trade and other receivables	(195)	984	235	1,321
Prepaid expenses and deposits	(17)	(22)	(6)	5
Trade and other payables	(572)	(807)	(1,441)	(328)
Effect of change in foreign exchange rates	31	49	(15)	(76)
	(753)	204	(1,227)	922
Attributable to:				
Operating	(340)	681	(208)	678
Investing	(401)	(250)	(1,017)	280
Financing	(12)	(227)	(2)	(36)
	(753)	204	(1,227)	922

The following represents the cash interest paid and received in each period:

($000s)

Cash interest paid and received

	Three months ended December 31		Nine months ended December 31	
	2019	**2018**	**2019**	**2018**
Cash interest paid	528	476	771	730
Cash interest received	1	1	2	9

18. COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company acquired an additional 21.43% working interest and received ministerial approval for the acquisition on August 11, 2015. In Q4 fiscal 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of a AUS$0.2 million on certification by an independent competent person appointed by Bengal Energy (Australia) Pty Ltd. of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of the first shipments of gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.

At December 31, 2019, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) [(1)]
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2021	12.9
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at December 31, 2019 at an exchange rate of AUS$1.00 = CAD$0.9128.

At December 31, 2019, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations October 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	621	155	312	154	-
Decommissioning and restoration	3,483	-	549	-	2,934
	4,104	155	861	154	2,934

19. SEGMENTED INFORMATION

As at December 31, 2019, the Company has two reportable operating segments, being the Australian oil and gas operations and corporate.

Revenue reported below represents revenue generated from external customers. There were no inter-segment sales in any of the reported periods.

The accounting policies of the reportable segments are the same as the group's accounting policies. Segment profit represents the profit earned by each segment without allocation of directors' fees, finance costs and income tax expense. This is the measure reported to the chief operating decision maker for the purposes of resource allocation and assessment of segment performance.

($000s)

For the nine months ended December 31, 2019

	Australia	Corporate	Total
Revenue	6,963	-	6,963
Interest revenue	1	1	2
Interest expense	960	11	971
Depletion and depreciation	1,154	41	1,195
Impairment	20	-	20
Net income (loss)	235	(935)	(700)
Exploration and evaluation expenditures	22	-	22
Petroleum and natural gas property expenditures	2,081	-	2,081

($000s)

December 31, 2019

Exploration and evaluation assets	9,370	-	9,370
Petroleum and natural gas properties	27,911	-	27,911

($000s)

For the nine months ended December 31, 2018

	Australia	Corporate	Total
Revenue	8,544	-	8,544
Interest revenue	8	1	9
Interest expense	740	-	740
Depletion and depreciation	1,076	8	1,084
Impairment	885	-	885
Net income (loss)	742	(1,073)	(331)
Exploration and evaluation expenditures	870	-	870
Petroleum and natural gas property expenditures	1,003	-	1,003

($000s)

December 31, 2018

Exploration and evaluation assets	9,802	-	9,802
Petroleum and natural gas properties	26,219	-	26,219

($000s)

For the three months ended December 31, 2019

	Australia	Corporate	Total
Revenue	2,425	-	2,425
Interest revenue	-	1	1
Interest expense	337	4	341
Depletion and depreciation	373	13	386
Impairment	-	-	-
Net income (loss)	849	(293)	556
Exploration and evaluation expenditures	12	-	12
Petroleum and natural gas property expenditures	334	-	334

($000s)

For the three months ended December 31, 2018

	Australia	Corporate	Total
Revenue	2,014	-	2,014
Interest revenue	-	1	1
Interest expense	248	-	248
Depletion and depreciation	352	2	354
Impairment	(70)	-	(70)
Net income (loss)	1,163	(280)	883
Exploration and evaluation expenditures	(42)	-	(42)
Petroleum and natural gas property expenditures	340	-	340

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Dr. Brian J. Moss
Robert D. Steele
Ian J. Towers (Chairman)
W. B. (Bill) Wheeler

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

James B. Howe (Chairman)
Robert D. Steele
W. B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Dr. Brian J. Moss
Ian J. Towers

GOVERNANCE AND COMPENSATION COMMITTEE

Peter D. Gaffney
Dr. Brian J. Moss
Robert D. Steele (Chairman)
Ian J. Towers

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Matthew Moorman, Chief Financial Officer
Bruce Allford, Secretary

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