International Exploration & Production

2019 Annual Report

Twelve Months Ended
March 31, 2019

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

It is with considerable pleasure and optimism that I address our valued shareholders at this time following our year end reporting period. During fiscal 2019, Bengal Energy Ltd. (“Bengal” or the “Company”) has been active across numerous fronts. This included focused geological and geophysical efforts to accelerate the drilling of an exciting westward extension to the productive Cuisinier field during the first half of fiscal 2019 and then execute on this program starting in Q4 fiscal 2019. In addition to the drilling program we also hydraulically stimulated three additional existing wells that will add to the expected increase in production. Geophysical and geological work continued through the fiscal 2019 year on advancing our opportunity on the ATP 934 exploration block. With continued support form our major banking partner, we successfully amended the re-determination date of our credit facility out to April 2020. In addition, the Company was active in identifying and analyzing production acquisition opportunities within our core areas in onshore Australia and in royalty friendly, resource rich jurisdictions here in North America. Expanding our regions in which to consider potential acquisitions is done with the full intention to add size and fund our strong growth initiatives in Australia. All these activities have positioned the Company well, setting the stage for near term growth and improved cash flow through an expanded acquisition strategy and a more robust development drilling plan over the next several years.

At Cuisinier, the Company is currently in full development mode, having completed the drilling and completion testing of three new wells on the western flank of the field. These wells will complete their tie-in and begin production during Q1 and Q2 fiscal 2020 (Q2 and Q3 calendar 2019). The total capital cost of the program is expected to be approximately CAD$5MM. In addition to the development program, we will be commencing a waterflood pilot on our C24 well later this year.

Although acquisition deal flow in Australia is generally thin, we have developed some important relationships and achieved significant headway during the year that could potentially help us expand our position not only in the oil market but also in the lucrative natural gas market in eastern Australia. The Australian east coast gas market is severely under-supplied and expected to remain so for the next 5-10 years. These market economics have resulted in the current natural gas prices to range between AUS$10-$12 per mcf. Bengal is actively looking for entry points into the east coast natural gas market to grow its production and cash flow, move to 100% operator status and diversify its resource mix.

Production for fiscal year ended March 31, 2019 averaged 298 bopd, a decrease of 17% over fiscal 2018 due to natural production declines. Bengal’s independently evaluated Proved Plus Probable (“2P”) reserves during the fiscal year ended March 31, 2019 is 6,026 Mbbls and Proved reserves are 2,257 Mbbls. The net present value (NPV10, before tax) of Bengal’s 2P reserves are $146 million, or $1.43 per share. The Company’s 2P net asset value before tax, which deducts net debt from the net present value (NPV10, before tax), is $132.5 million or $1.30 per share. The 2P after tax net asset value is $95.9 million and $0.94 per share. The net present value (NPV10, before tax) of Bengal’s Proved reserves are $59 million, or $0.58 per share. The Company’s Proved net asset value before tax, deducting net debt from the net present value (NPV10, before tax), is $45.4 million or $0.44 per share. The Proved after tax net asset value is $34.5 million or $0.34 per share. These increases in value are primarily a result of higher forecast crude oil prices. We remain confident in our ability to further grow the size and value of our reserves base through future drilling programs and scaling up from the water injection pilot to a field-wide reservoir pressure maintenance program.

Now that Bengal has a 100% interest in ATP 934, we have commenced discussions with third parties who may be interested in farming in on this block. This exploration gas block has continued to be of interest as the overall east coast gas market continues to be robust.

The near-term outlook for crude oil and natural gas prices in the Australian market has strengthened considerably with the rise in current and forecast Brent crude oil pricing in US$ and a continued shortage of readily available natural gas is creating upward pressure on spot pricing in east coast markets. Natural gas prices have reached record highs in eastern Australia due to the significant increase in demand associated with several newly commissioned LNG export projects. We are encouraged by the outlook for natural gas demand continuing to grow over the medium term and we are also bullish on the multiple marketing opportunities to optimize ATP 934 natural gas pricing and returns.

Bengal also successfully negotiated an amendment to its secured credit facility (the “Credit Facility”) in the spring of 2019 with the Australian-based Westpac Institutional Bank, which includes a deferment of principal payments on the Credit Facility. The Credit Facility now has an expiry date of April 2020 and continues to provide a borrowing base of US$ 12.5 million, of which the full amount is currently drawn.

I would also like to address our recent stock price and the volatility that is affecting shareholders at the time of this writing. Officers, Directors and other close insiders remain committed to the Company and its ongoing strategy and have not engaged in any selling. In addition, management is not aware of any technical issues responsible for the current decline in value. In contrast, management remains bullish towards its ability to grow production and value. We remain bullish on our core Australian market, which is a very strong platform for future growth given the unique combination of fiscal stability, attractive oil and gas market fundamentals, established infrastructure and high-impact exploration and development potential. I want to thank our strong and supportive Board of Directors, our diligent and talented technical team, as well as each of our shareholders for your support as we continue to methodically develop our world-class assets.

Sincerely,

(signed) “Chayan Chakrabarty”

Chayan Chakrabarty

President & CEO

Note: this Message to Shareholders contains forward-looking statements and is subject to the forward looking statement disclaimer in the Management’s Discussion & Analysis for the Years Ended March 31, 2019 and 2018.

Bengal
ENERGY LTD.

International exploration & production

Management’s Discussion & Analysis

Three and Twelve Months Ended
March 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 and for the three months and twelve months ended March 31, 2019.

This MD&A dated June 20, 2019 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2019 and 2018. The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The functional currency of the Company's operating subsidiary is the Australian dollar; 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 Measures", "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 March 31, 2019 may be referred to as "fourth quarter fiscal 2019", "Q4 FY 2019", "current quarter", and "the quarter". The comparative three months ended March 31, 2018, may be referred to as "fourth quarter fiscal 2018", "Q4 FY 2018", "prior year's quarter", and "2018 quarter". The year ended March 31, 2019, may be referred to as "fiscal 2019", "current year", and "the year". The comparative year ended March 31, 2018, may be referred to as "the previous year", "prior year", and "fiscal 2018".

FOURTH QUARTER FISCAL 2019 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $2.7 million in the fourth quarter of fiscal 2019, which is 4% lower than the $2.8 million recorded in Q4 fiscal 2018. Full year fiscal 2019 sales revenue was $11.2 million compared to $10.7 million for the full year fiscal 2018. The improved full year performance in fiscal 2019 compared to fiscal 2018 was due primarily to an overall higher average US Brent price, despite a lower overall production volume.
- **Hedging** – The Company's Credit Facility requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. At year-end fiscal 2019, the realized loss on financial instruments was $1.2 million while an unrealized gain on financial instruments of $1.1 million was recorded. The quarter ended March 31, 2019 had hedges in place at US$55.40/bbl while the two subsequent quarters have a portion of expected production hedged at over US$72/bbl. For the quarter ending December 31, 2019, a portion of production has been hedged using puts and swaps at US$54.20/bbl. For the period Jan –March 2020, the hedging program has a combination of puts and swaps at US$63.74/bbl.
- **Funds from Operations** – Bengal generated funds from operations of $0.8 million during Q4 fiscal 2019 compared to $0.5 million of funds from operations in Q4 fiscal 2018. For the full year fiscal 2019, the Company generated funds from operations of $2.2 million, down from $3.7 million of funds from operations in fiscal 2018. The primary reason for the decrease in funds from operations during fiscal 2019 as compared to fiscal 2018 was the impact of the realized loss on financial instruments.
- **Net loss** – Bengal reported a net loss of $2.1 million for the current quarter compared to a net loss of $12.5 million in the fourth quarter of fiscal 2018. For the full year fiscal 2019, the Company reported a net loss of $2.5 million compared to fiscal 2018 net loss of $12.3 million. The primary driver for the net loss for both the current quarter and full year fiscal 2019 was an asset impairment of $1.9 million and $2.8 million respectively.
- **Adjusted Net Income –** Bengal reported adjusted net income of $0.4 million for the current quarter and $0.5 million for the full year fiscal 2019. Net income is adjusted for unrealized gain (loss) on financial instruments, the unrealized foreign exchange gain (loss) for the period and the non-cash impairment of non-current assets.

Operational Summary:

- **Production Volumes** – The Company's share of total production in the current quarter was 25,303 bbls, which is a 16% decline from the 30,050 bbls produced in the fourth quarter of fiscal 2018. The current quarter production averaged 281 bbls per day compared to 334 bbls per day produced in the fourth quarter of fiscal 2018. Full year fiscal 2019 saw total production of 108,731 compared to 131,455 for full year fiscal 2018. The full year fiscal 2019 production per day averaged 298 bbls compared to 360 bbls per day for the full year fiscal 2018. Normal production declines and reduced capital spending in time to realise any increase in production during the fiscal year, are the reason for the reduction in production for year over year.
- **Capital Expenditures** – Bengal commenced its five well development drilling program and capital expenditures towards the waterflood pilot in the fourth quarter of fiscal 2019. The drilling program completion is expected to occur by the end of Q2 fiscal 2020. The waterflood pilot will take place during second quarter of fiscal 2020. During Q4 fiscal 2019, Bengal incurred $2.4 million in capital expenditures related to this capital program. Full year fiscal 2019 saw total capital expenditure of $4.3 million, which included the exploration well drilling in Q2 fiscal 2019.

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, Barrolka, Cuisinier and Tookoonooka, 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's 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 for the Cuisinier field, PL 303 and PL 1028.

AUSTRALIA – Cooper Basin, Queensland

PL 303 Barta Block Cuisinier (controlling permit ATP 752) (30.357% WI)

During the Q3 and Q4 fiscal 2019, the Company's joint venture on Barta Block Cuisinier PL 303 (the "Joint Venture") conducted a fracture stimulation campaign on four wells. Three of the four wells were successful and the Cuisinier North-1, Shefu-1 and Cuisinier-24 wells were brought online in September. The Cuisinier-19 well was fracture stimulated in a later program during Q3 fiscal 2019 but was unsuccessful. Prior to the frac program, the aggregate gross production from the three wells was 93 bbls/d. Subsequent to the frac program, the aggregate initial production was 322 bbls/d, for an incremental increase of 229 gross bbls/d (an incremental 69 bbls/d net to Bengal). These post frac rates have been monitored closely over the last quarter with positive productivity levels observed. Ongoing evaluation of previously stimulated wells has assisted the Joint Venture in planning for its future drilling campaigns. These campaigns are designed to allow for fracture stimulations to occur upon completion as required. This will result in operational efficiencies and cost savings in addition to potentially improved initial production rates on the stimulated wells.

The fiscal year 2019 drilling program consisting of four development wells and one appraisal well within PL 303 started in February 2019. Two of the four development wells, Cuisinier 29 and Cuisinier 30 were located on the northwest side of the Cuisinier pool close to production infrastructure and were designed to extend the producing area while potentially increasing the pool reserves area. The Cuisinier 29 well was successfully drilled, cased and suspended in late February and discovered a new oil pool in the DC-50 sand that lies below the target DC-70 zone. The DC-50 sand is approximately 12.5 metres thick with an estimated 6.9 metres of internally estimated net oil pay. In addition, the well intersected approximately 1.1 metres of internally estimated net oil pay in the target zone DC-70 sand, which also shows virgin pressure. The well has been cased and suspended as a future oil producer.

The Cuisinier-27 and 28 development wells were located in the heart of the Cuisinier pool offsetting the planned waterflood pilot. Both of these wells met pre-drill expectations encountering 4.1 and 4.6 metres of internally estimated net oil pay respectively. These wells have been cased and suspended as Murta DC-70 oil wells. The fourth development well, Cuisinier-30, encountered 7.2 metres of Murta DC-70 sand; however the zone was low and water bearing. This well was therefore plugged and abandoned.

The Cuisinier-26 appraisal well was drilled in the southernmost part of PL 303 and was intended to extend the known producing sand fairway present in the core of the pool. The well encountered 0.8 metres of internally estimated net oil pay in the Murta DC-70 and was plugged and abandoned as uneconomic. In calendar Q1 FY 2020, the three successful wells will be connected for production and an assessment of the productivity will be made. A development plan for the new DC-50 sand will be prepared based on initial production results. First oil sales from the new 2019 wells are expected in early calendar Q2 FY 2020. Results to date for the 2019 Cuisinier drilling campaign have been encouraging for further appraisal of the western extension of the Cuisinier oil field and particularly for the new zone in the Cuisinier 29 well. The program has shown a total of four oil reservoir zones that were encountered in three of the four development wells drilled. The new pool discovery in the DC-50 sand in the Cuisinier-29 well may provide further development drilling opportunities and pool expansion upside. Further results will be released upon program completion, which is anticipated to occur in early calendar Q2 FY 2020.

The Joint Venture has also initiated the implementation of a pilot reservoir pressure maintenance scheme, which is planned to commence during calendar Q2 FY 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 weak 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 generate a positive response in production performance of up to four offsetting producing wells. In addition, the planned program will also complement future water flood expansion phases currently in the initial planning stages.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company’s 100% owned gas exploration block that was acquired in March 2015. Bengal’s completion of seismic amplitude inversion studies have highlighted the most favourable areas of the permit allowing for additional detailed geophysical work. The reprocessing of select 2D seismic lines will be valuable in selection of future drilling locations and locating the area of potential 3D seismic acquisition in fiscal year 2021. In addition to inversion, the Company has also embarked on depth image processing to help mitigate the velocity impact of near surface velocity changes, known to affect the quality of the time to the depth conversion. This work is expected to be completed by the end of June 2019 and will further advance the de-risking of previously high graded prospect areas.

Bengal has consolidated its ownership to 100% working interest in the permit through the acquisition of the remaining non-owned interest and now has operatorship. Discussions are ongoing with third parties who may have an interest in farming in on this block, supporting the next phase of exploration thereby further de-risking the natural gas potential of the permit.

OPERATING SUMMARY

($000s except per share, %, volumes and netback amounts)	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Oil revenue	$ 2,667	$ 2,783	$ 11,211	$ 10,710
Operating netback[(1)]	$ 1,944	$ 1,282	$ 5,780	$ 6,918
Cash from operations	$ 635	$ 858	$ 2,691	$ 3,627
Funds from operations[(2)]	$ 842	$ 525	$ 2,220	$ 3,737
Per share ($) (basic and diluted)	$ 0.01	$ 0.01	$ 0.02	$ 0.04
Net loss	$ (2,144)	$ (12,526)	$ (2,475)	$(12,271)
Per share ($) (basic and diluted)	$ (0.02)	$ (0.12)	$ (0.03)	$ (0.12)
Adjusted net income (loss)[(3)]	$ 397	$ (143)	$ 525	$ 1,459
Per share ($) (basic and diluted)	$ 0.00	$ 0.00	$ 0.01	$ 0.01
Capital expenditures	$ 2,473	$ 939	$ 4,346	$ 3,511
Oil volumes (bbl/d)	281	334	298	360
Netback[(1)]($/bbl)	$ 76.82	$ 42.66	$ 53.16	$ 52.63

(1) Operating netback is a non-IFRS measure and includes realized (loss) gain on financial instruments. 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 11 of this Annual Report.
(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. Funds from operations per share is a non-IFRS measure calculated as 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 25 of this Annual Report.
(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 25 of this Annual Report.
(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 March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Oil production (bbls/d)	281	334	298	360
Oil production (bbls)	25,303	30,050	108,731	131,455

Revenue/Pricing

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

		Three months ended March 31		Twelve months ended March 31	
		2019	2018	2019	2018
	Oil lifting				
	Volume (000s bbls)	27.2	31.4	119.7	134.1
	Weighted average price ($US/bbl)	66.18	70.45	73.83	60.76
	Sales ($US000's)	1,800	2,212	8,837	8,148
A.	Sales ($000's)	2,412	2,853	12,070	10,383
	Pipeline oil				
	Volume (000s bbls), change	(1.9)	(1.4)	(11.0)	(2.7)
	Price ($US/bbl), change	18.67	1.56	8.62	14.70
	Net sales ($US000's)	191	(54)	(633)	252
B.	Net sales ($000's)	255	(70)	(859)	327
A.+B.	**Total oil sales** ($000s)	2,667	2,783	11,211	10,710

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.

Realized crude oil price during Q4 fiscal 2019 was significantly impacted by the decline in US Brent as compared to Q4 fiscal 2018. The realized weighted average price of oil-lifting sales was US$ 66.18/bbl and US$70.45/bbl for Q4 FY 2019 and 2018 respectively. When combined with lower oil lifting volumes in Q4 fiscal 2019 of 27.2K bbls as compared to 31.4K bbls in Q4 fiscal 2018, oil-lifting sales were lower at $2.4 million for the current quarter as compared to $2.8 million for Q4 fiscal 2018. For the full year fiscal 2019, the realized weighted average price of oil-lifting sales was US$73.83/bbl as compared to US$60.76/bbl for the full year fiscal 2018 or 22% higher. Despite oil-lifting volumes being lower in fiscal 2019 at 119.7K bbls as compared to oil lifting volumes in fiscal 2018 at 134.1K bbls, or 11% lower, oil-lifting sales were higher in fiscal 2019 at $12.1 million compared to $10.4 million in fiscal 2018. When oil-lifting sales are adjusted for the change in value of the pipeline oil both for the current quarter of $0.3 million and full year fiscal 2019 of ($0.9 million), Bengal's total oil sales are $2.7 million for the current quarter and $11.2 million for the full year fiscal 2019.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2019	2018	2019	2018
Brent oil ($/bbl)	84.02	86.61	91.90	74.23
Brent oil (US$/bbl)	63.17	66.81	70.15	57.57
Number of CAD$ for 1 AUS$	0.95	0.99	0.96	0.99
Number of CAD$ for 1 US$	1.33	1.26	1.31	1.28

($000s)

Operating Netbacks

	Three months ended March 31		Twelve months ended March 31	
	2019	**2018**	**2019**	**2018**
Oil sales	2,667	2,783	11,211	10,710
Realized (loss) gain on financial instruments	(90)	(288)	(1,236)	568
Royalties	(59)	(136)	(570)	(642)
Operating expenses	(574)	(1,077)	(3,625)	(3,718)
Operating Netback	1,944	1,282	5,780	6,918
($/bbl)				
Oil sales	105.40	92.61	103.11	81.47
Realized (loss) gain on financial instruments	(3.56)	(9.58)	(11.37)	4.32
Royalties	(2.33)	(4.53)	(5.24)	(4.88)
Operating expenses	(22.69)	(35.84)	(33.34)	(28.28)
Operating Netback	76.82	42.66	53.16	52.63

Netbacks in Q4 fiscal 2019 were $1.9 million or $76.82/bbl compared to Q4 fiscal 2018 at $1.3 million or $42.66/bbl. The primary reason for the increase in operating netbacks during the current quarter compared to Q4 fiscal 2018 was the realization of a $0.4 million credit due to Bengal as a result of an audit of our JV partner. This credit reduced the Q4 fiscal 2019 operating expenses by $13.67/ bbl. As a result of the credit, operating expenses for the current quarter were $22.69/bbl as compared to $35.84/bbl for Q4 fiscal 2018. For the full year fiscal 2019, netbacks were $5.8 million or $53.16/ bbl. The credit reduced the full year operating expenses by $3.18/bbl. The realized loss on financial instruments of $1.2 million is due to the US$ 47/bbl hedges throughout the nine months ended Q4 fiscal 2019. Royalties have been calculated to be 5.08% of oil sales for full year fiscal 2019 as compared to 6% for the full year fiscal 2018 due to increased capital expenditure in fiscal 2019. The reduced royalty expense in Q4 fiscal 2019 is due to an adjustment made during the current quarter, to reflect the annual fiscal 2019 reduced royalty expense. Comparative operating expenses for 2018 were much lower as a result of a significantly higher credit received from a Joint Venture audit. The impact of last years realized credit was $22.66/ bbl for Q4 fiscal 2018 and $5.18/ bbl for the full fiscal 2018.

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 March 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
April 1, 2019 – April 30, 2019	Oil - swap	5,000	73.28	73.28
				-

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
May 1, 2019 – May 31, 2019	Oil - swap	5,000	72.92	72.92

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
June 1, 2019 – June 30, 2019	Oil - swap	5,000	72.92	72.92

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
July 1, 2019 – July 31, 2019	Oil - swap	5,000	75.03	75.03

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	60	-	60
Non-current fair value of financial instruments	-	-	-
	60	-	60

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
August 1, 2019 – August 31, 2019	Oil - swap	5,000	74.69	74.69

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	58	-	58
Non-current fair value of financial instruments	-	-	-
	58	-	58

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
September 1, 2019 – September 30, 2019	Oil - swap	5,000	74.37	74.37

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	57	-	57
Non-current fair value of financial instruments	-	-	-
	57	-	57

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(113)	18	(95)
Non-current fair value of financial instruments	-	-	-
	(113)	18	(95)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(26)	-	(26)
Non-current fair value of financial instruments	-	-	-
	(26)	-	(26)

Total			
($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	159	18	177
Non-current fair value of financial instruments	-	-	-
	159	18	177

The fair value of the financial contracts outstanding as at March 31, 2019 is $0.2 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 year, 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 twelve months ended March 31, 2019, the derivative commodity contracts resulted in a realized loss of $1.2 million (March 31, 2018 – gain of $0.6 million) and an unrealized gain of $1.1 million (March 31, 2018 – loss of $1.7 million).

Royalties

Royalties	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Royalty expense ($000s)	59	136	570	642
$/bbl	2.33	4.53	5.24	4.88
% of revenue	2	5	5	6

In Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty of 1%. The royalty rate is applied to gross revenues after deducting an allowance for allowable capital, transportation and operating costs. An increase in capital expenditure in fiscal 2019 has resulted in a reduced royalty expense rate of 5.08% of oil sales revenue.

Royalties per barrel in Q4 fiscal 2019 were 2% of revenue due to an adjustment made to reflect the annual fiscal royalty rate of 5.08%.

Operating Expenses

($000s) **Operating expenses**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Production	(231)	151	307	(239)
Transportation	805	926	3,318	3,957
	574	1,077	3,625	3,718
Production - $/bbl	(9.13)	5.02	2.82	(1.82)
Transportation - $/bbl	31.81	30.82	30.52	30.10
	22.68	35.84	33.34	28.28

Total operating expense during the fourth quarter fiscal 2019 was $0.6 million, 47% lower than the fourth quarter of fiscal 2018. The lower operating expense was due to the realization of a $0.4 million or $13.67/bbl credit due to Bengal as a result of an audit of our JV partner during the current quarter and charged against the production line item. For Q4 fiscal 2019, the operating expense per barrel was $22.68/bbl as compared to $35.84/bbl for Q4 fiscal 2018. Full year fiscal 2019 operating expense was $3.6 million or $33.34/bbl. The impact of the credit on full year fiscal 2019 was $3.18/bbl. This compares to the operating expense for fiscal 2018 of $3.7 million or $28.28/bbl. The lower cost per barrel in fiscal 2018 is due to higher production than in fiscal 2019 even after the JV credits are taken into account.

General and Administrative (G&A) Expenses

($000s) **G&A**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Total G&A	842	834	3,286	3,193
Capitalized Staff G&A	(36)	(69)	(190)	(295)
Capitalized Contractors G&A	-	(151)	(196)	(500)
Net G&A	806	614	2,900	2,398

Net G&A expenses in the fourth quarter fiscal 2019 were $0.8 million as compared to $0.6 million for the fourth quarter fiscal 2018. The full year fiscal 2019 saw net G&A expense at $2.9 million compared to $2.4 million for the full year fiscal 2018. The 21% increase or $500K in net G&A expense for the full year fiscal 2019 is due to a lower amount of activity by staff and contractors that was charged to capital projects

Share-based Compensation ("SBC")

($000s) **SBC**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Expensed share-based compensation	13	28	69	95
Capitalized share-based compensation	1	5	8	15
	14	33	77	110

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; they vest one-third on the first anniversary of the grant date and one-third on each of the following two annual anniversaries.

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended March 31 2019	2018	Twelve months ended March 31 2019	2018
Petroleum and natural gas properties	370	573	1,446	2,026
Other assets	3	3	11	14
	373	576	1,457	2,040
Petroleum and natural gas properties - $/bbl	14.62	19.07	13.30	15.41

The Company's 2P reserve volumes at March 31, 2019, decreased 326,000 bbls compared to March 31, 2018. In addition, capital costs to develop proven and probable reserves at March 31, 2019, was $62.4 million compared to $58.1 million at March 31, 2018.

Production in Q4 fiscal 2019 was 25,303 bbls compared with 30,050 bbls in Q4 fiscal 2018. These amounts resulted in a depletion rate of 0.41% for Q4 fiscal 2019, compared to 0.47% for the comparative period. This lower depletion rate more than compensated for the increased capital costs to develop proven and probable reserves.

Production for the fiscal year 2019 was 108,731 bbls compared to 131,455 bbls for the previous year, resulting in a lower depletion rate for fiscal 2019. This lower depletion rate again more than compensated for the increased capital costs to develop proven and probable reserves at March 31, 2019.

Impairment

($000s) Impairment expense	Three months ended March 31 2019	2018	Twelve months ended March 31 2019	2018
Exploration and evaluation assets	-	12,167	885	12,167
Petroleum and natural gas properties	1,906	-	1,906	-
	1,906	12,167	2,791	12,167

During Q4 fiscal 2019, the Company took an impairment charge of $1.9 million due to two development wells, Cuisinier-26 and Cuisinier-30, deemed to be uneconomic following the five well drilling program and additional appraisal well, C-19, also deemed to be uneconomic. In Q2 fiscal 2019, the Company impaired an exploration well drilled and deemed uneconomic. At March 31, 2018, the Company took a $12.2 million impairment to its Exploration and Evaluation assets primarily related to ATP 732.

Finance Expense

($000s) **Finance expense**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Interest income	(1)	(1)	(10)	(13)
Accretion expense on decommissioning and restoration liability	9	9	39	37
Letter of credit charges	-	-	8	-
Interest on Credit Facility	294	236	1,034	954
	302	244	1,071	978

Interest on the Credit Facility had been based on US dollar LIBOR + 3.2% margin. The revised Credit Facility amendment dated November 2018 increased the margin to 3.75% effective January 1, 2019.

CAPITAL EXPENDITURES

($000s) **Capital expenditures**	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
Geological and geophysical	99	1,586	309	2,139
Drilling	1,530	-	2,360	(52)
Completions	844	(1,156)	1,677	915
Acquisition	-	509	-	509
	2,473	939	4,346	3,511
Exploration and evaluation expenditures	60	1,996	930	2,277
Development and production expenditures	2,413	(1,057)	3,416	1,234
	2,473	939	4,346	3,511

The development and production expenditure of $2.4 million in Q4 fiscal 2019 relates to the commencement of the five well drilling program and waterflood pilot that will continue through Q3 fiscal 2020. The credit of $1.1 million in Q4 fiscal 2018 was a result of a transfer of costs from PP&E to E&E.

CREDIT FACILITY

In October 2014, Bengal closed its US$25.0 million secured credit facility (the “Credit Facility”) with Westpac Institutional Bank (“Westpac”) and placed an initial draw on November 12, 2014 of US$14.0 million. On August 25, 2016, following a US$1.5 million repayment, the Company extended the Credit Facility by 18 months to December 2018 with a borrowing base of US$15.0 million. On September 25, 2017, the Company extended the Credit Facility to December 2019 with a borrowing base of US$12.5 million. On March 5, 2018, the Credit Facility was further amended to delay the majority of principal payments into

2019. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US LIBOR plus 3.2%.

The Credit Facility is structured as a reserve-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. Under the amendment to the Credit Facility dated March 5, 2018, the Company was required to make a US$1.5 million principal payment on December 31, 2018 and a further US$5.0 million on June 30, 2019 and US$6.0 million on December 30, 2019. In addition, the Company had agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement that requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve-based review by April 30, 2019. Pursuant to these terms, the Company repaid US$131,000 during Q3 fiscal 2019.

On November 19, 2018, the Company and Westpac entered into a revised amendment agreement to the Credit Facility to defer all principal payments previously required under the March 5, 2018 amendment to February 15, 2020. This revised amendment now requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. All other terms and conditions previously provided under the March 5, 2018 amendment remain in effect. There was an interest rate change from LIBOR plus 3.2% to 3.75% effective January 1, 2019. Given the repayment date of February 15, 2020, the debt has been classified as current at March 31, 2019.

On May 29, 2019, the Company and Westpac entered into an amendment to the November 19, 2018 agreement that has all 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'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 March 31, 2019.

SHARE CAPITAL

Trading history	**Three months ended March 31**		**Twelve months ended March 31**	
	2019	**2018**	**2019**	**2018**
High ($)	0.14	0.13	0.18	0.17
Low ($)	0.10	0.09	0.09	0.08
Close ($)	0.12	0.10	0.12	0.10
Volume (000s)	2,178	2,801	9,778	15,454
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 June 20, 2019, there were 102,266,694 common shares issued and outstanding, together with 4,102,500 outstanding options.

LIQUIDITY RISK AND CAPITAL RESOURCES

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, fair value of financial instruments and Credit Facility, amounting to $19.1 million at March 31, 2019 (March 31, 2018 - $19.3 million).

At March 31, 2019, the Company had a working capital deficiency of $12.7 million, including cash and short-term deposits of $2.9 million and restricted cash of $0.1 million, compared to working capital of $3.4 million at March 31, 2018 and working capital of $6.3 million at December 31, 2018. The working capital deficit of $12.7 million is primarily a result of the reclassification of the bank debt of $16.5 million to current from long term. Notwithstanding the bank debt reclassification, the working capital at March 31, 2019 would have been a positive $3.7 million. The Company does not anticipate any difficulty in meeting its current obligations as the Company has generated positive working capital and is forecasted to continue to generate positive working capital. The Company has no available undrawn debt capacity under its Westpac Credit Facility

The Company has significant spending commitments to be incurred by February 2021 on ATP 934 and has its US$12.4 million Credit Facility that matures in April 2020. Management anticipates that future and ongoing discussions with Westpac will defer the current repayment date and that operating and capital requirements will be met out of operating cash flows in addition to alternative forms of capital raising. There can be no guarantees that alternative forms of capital raising will be available or obtained on terms that are satisfactory to the Company. Should the Bank not further defer principal payments and the Company be unsuccessful in obtaining additional funding, there will be an adverse impact to the Company's liquidity.

The majority of the Company's oil sales are benchmarked on Brent prices, which averaged US$70.15/bbl for the twelve months, ended March 31, 2019. 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 2019 and beyond.

The table below indicates the payment schedule for the Company's Credit Facility:

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

Management is in discussion with the lender to further amend the current repayment terms. 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.

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 cubic feet 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 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 above.

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

Country and permit (1)	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$)
Onshore Australia – ATP 934	260 km^2 3D seismic and three wells with fracs and casing	February 2021	13.4
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2019 at an exchange rate of AUS$1.00 = CAD$ 0.9473.

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

($000s) Contractual obligations April 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	737	155	311	271	-

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2018	Mar 31 2018 Q4 2018	Dec 31 2017 Q3 2018	Sep 30 2017 Q2 2018	Jun 30 2017 Q1 2017
Oil sales	2,667	2,014	3,315	3,215	2,783	3,211	2,410	2,306
Cash from operations	635	434	603	1,019	858	431	648	1,690
Funds from (used in) operations(1)	842	(247)	750	875	525	1,268	110	1,834
per share – basic and diluted ($)	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.02
Net (loss) income	(2,144)	883	(728)	(486)	(12,526)	206	(500)	54
per share – basic and diluted ($)	(0.02)	0.01	(0.01)	0.00	(0.12)	0.00	0.00	0.01
Capital expenditures	2,473	298	1,274	301	939	342	1,527	703
Working capital (deficiency)	(12,740)	6,331	(3,353)	(2,915)	3,385	(637)	2,107	(2,477)
Total assets	42,489	44,291	43,547	44,867	45,714	56,932	56,032	57,104
Shares outstanding (000s)	102,667	102,667	102,667	102,667	102,667	102,667	102,667	102,667
Operations:								
Oil volumes (bbls)	281	300	292	318	334	354	383	369
Netback(1) ($/bbl)	76.82	22.54	59.58	55.69	42.66	63.13	27.21	78.02

(1) See “Non-IFRS Measurements” on page 19 of this MD&A.

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. Significant declines in $US Brent during Q3 fiscal 2019 resulted in the lowest sales revenue in the past eight quarters. The Company began a five well drilling program in Q4 fiscal 2019 that will be completed by the end of Q1 fiscal 2020. The current quarter also saw a significant rebound in $US Brent pricing that saw a return to strong sales revenue and cash from operations.

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 March 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. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are out-lined below.

(a) Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of Cash-generating units

Bengal's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Recognition of deferred income tax assets

The recognition of deferred income tax assets requires judgments regarding the likelihood and applicability of future income tax deductions. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and ability to apply income tax deductions.

(b) Key sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of assets, and impairment charges and reversal will affect profit or loss.

Reserves

The estimate of petroleum and natural gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's development and production assets has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

NEW ACCOUNTING STANDARDS

On April 1, 2018, Bengal retrospectively adopted IFRS 15 Revenue from Contracts with Customers ("IFRS 15"). There were no adjustments made to the April 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are detailed in Note 13 to the March 31, 2019 consolidated financial statements.

On April 1, 2018, Bengal retrospectively adopted IFRS 9 Financial Instruments ("IFRS 9"), which includes new requirements for the classification and measurement of financial assets, a new credit loss impairment model and a new model to be used for hedge accounting for risk management contracts. The Company currently has risk management contracts but does not use hedge accounting. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition. The additional disclosures required by IFRS 9 are detailed in Note 4 to the March 31, 2019 consolidated financial statements.

FUTURE ACCOUNTING STANDARDS

IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 Leases ("IFRS 16"). This standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than 12 months. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The Company's assessment of the impact of the adoption of the standard is still in progress.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, 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. Netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Netback per barrel equals 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 as 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 March 31 2019	2018	Twelve months ended March 31 2019	2018
Cash from operating activities	635	858	2,691	3,627
Changes in non-cash working capital	207	(333)	(471)	110
Funds from operations	842	525	2,220	3,737

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

($000s)	Three months ended March 31 2019	2018	Twelve months ended March 31 2019	2018
Net loss	(2,144)	(12,526)	(2,475)	(12,271)
Unrealized loss (gain) on financial instruments	740	(39)	(1,086)	1,661
Unrealized foreign exchange (gain) loss	(105)	255	1,295	(98)
Non-cash impairment of non-current assets	1,906	12,167	2,791	12,167
Adjusted net income (loss)	397	(143)	525	1,459

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
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
Santos		Santos Ltd.
WI	-	working interest
YTD	-	year to date

RISK FACTORS

Companies engaged in the oil and gas industry are exposed to a number of business risks, which can be described as operational, financial and political risks, many of which are outside of the Company's control. More specifically, these include risks of economically finding reserves and producing oil and gas in commercial quantities, marketing the production, commodity prices, environmental and safety risks, and risks associated with the foreign jurisdiction in which the Company operates. In order to mitigate these risks, the Company has an experienced base of qualified technical and financial personnel in both Canada and Australia. Further, the Company has focused its foreign operations and plans to target future foreign operations in known and prospective hydrocarbon basins in jurisdictions that have previously established long-term oil and gas ventures with foreign oil and gas companies.

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 below 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 below does not purport to be an exhaustive summary of the risks affecting Bengal.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Bengal will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of Bengal will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that Bengal will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Bengal may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Bengal attempts to minimize exploration, development and production risks by utilizing a high-end technical team with extensive experience and multidisciplinary skill sets to assure the highest probability of success in its drilling efforts. Bengal's collaboration of a team of seasoned veterans in the oil and gas business, each with a unique expertise in the various upstream to downstream technical disciplines of prospect generation to operations, provides the best assurance of competency, risk management and drilling success. A full cycle economic model is utilized to evaluate all hydrocarbon prospects. Detailed geological and geophysical techniques are regularly employed including 3D seismic, petrography, sedimentology, petrophysical log analysis and regional geological evaluation.

Risks Associated with Foreign Operations

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments and other regulatory agencies in the foreign jurisdictions in which Bengal operates and intends to operate in the future may make sudden changes in laws relating to taxation or impose higher tax rates, which may affect Bengal’s operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal, which can result in the Company having to pay significant penalties and fines. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities that have prices determined based on world demand, supply and other factors, all of which are beyond the control of Bengal. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of Bengal’s oil and gas reserves. Bengal might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Bengal’s future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition to establishing markets for its oil and natural gas, Bengal must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas, which may be acquired or discovered by Bengal, will be affected by numerous factors beyond its control. The ability of Bengal to market its natural gas may depend upon its ability to acquire space on pipelines, which deliver natural gas to commercial markets. Bengal will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Substantial Capital Requirements and Liquidity

Bengal’s cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Bengal may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Bengal to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Bengal’s revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Bengal’s ability to expend the necessary capital to replace its reserves or to maintain its production. If Bengal’s funds from operations are not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Bengal.

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.

Health, Safety and Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge.

Insurance

Bengal's involvement in the exploration for and development of oil and gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Bengal has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Bengal may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Bengal. The occurrence of a significant event that Bengal is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bengal's financial position, results of operations or prospects.

Competition

Bengal actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel resources than Bengal. Bengal's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Bengal's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

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," "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 program and waterflood pilot;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *The expectation that the Joint Venture's drilling campaign will allow for fracture stimulations to occur upon completion as required and result in operational efficiencies, cost savings and improved initial production rates;*
- *The timing of first oil sales from the new 2019 wells;*
- *The expected operational efficiencies and cost savings as well as potentially improved initial production rates in relation to the fracture stimulation campaign on four wells on ATP 752;*
- *The potential of further development drilling opportunities and pool expansion upside in the DC-50 sand in the Cuisinier 29 well;*
- *The timing of further results on the 2019 drilling program completion;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of up to four offsetting producing wells in the Cuisinier field;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *The possibility of third parties farming in on ATP 934 Barrolka*
- *;The possibility of additional reprocessing and acquisition of 2D and 3D seismic on ATP 934;*
- *;*
- *Projections of market prices and costs including, but not limited to, expected royalty rates;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *That required payments will be met out of operation cash flows and alternative forms of financing;*
- *Expectations regarding the Credit Facility and the results of discussions with Westpac;*
- *Bengal's ability to finance its working capital deficiency and to source funds for the same;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs; and*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures, share issuances or other alternative forms of capital raising and funds will be sufficient to meet requirements including but not limited to Bengal's exploration activities through fiscal 2020 and capital program.*

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

Unless otherwise specified, reserves data set forth in this document is based upon an independent reserve assessment and evaluation prepared by GLJ with an effective date of March 31, 2019 (the "GLJ Report"). The GLJ Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities ("NI 51-101").

This document includes estimates of thickness net pay, which estimates may be considered to be anticipated results under NI 51-101. The estimates were prepared internally. References to thickness of "net oil pay" or of a formation where evidence of hydrocarbons has been encountered is not necessarily an indicator that hydrocarbons will be recoverable in commercial quantities or in any estimated volume. Bengal may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves. Well test results should be considered as preliminary and not necessarily indicative of long-term performance or of ultimate recovery. Well log interpretations indicating oil and gas accumulations are not necessarily indicative of future production or ultimate recovery. If it is indicated that a pressure transient analysis or well-test interpretation has not been carried out, any data disclosed in that respect should be considered preliminary until such analysis has been completed.

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
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG

Consolidated Financial Statements

Years Ended
March 31, 2019 and 2018

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards outlined in the notes to the consolidated financial statements. The consolidated financial statements include certain estimates that reflect management's best judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. In the opinion of management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards. The financial information contained in the annual report is consistent with that in the consolidated financial statements.

Management is also responsible for establishing and maintaining appropriate systems of internal control over the Company's financial reporting. The internal control system was designed to provide reasonable assurance to management regarding the preparation and presentation of the consolidated financial statements. Management tested and evaluated the effectiveness of its disclosure controls and procedures and internal controls over financial reporting as at March 31, 2019. During this evaluation, management identified material weaknesses due to the limited number of finance and accounting personnel at the Company dealing with complex and non-routine accounting transactions that may arise and due to a lack of segregation of duties and as a result the controls are not considered effective. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable but not absolute assurance that financial information is accurate and complete.

KPMG LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent annual general meeting, to examine the consolidated financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The audit committee of the Board of Directors with all of its members being independent directors, have reviewed the consolidated financial statements including notes thereto with management and KPMG LLP. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

(signed) "Chayan Chakrabarty"
Chayan Chakrabarty
President & Chief Executive Officer

(signed) "Matthew Moorman"
Matthew Moorman
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bengal Energy Ltd.

Opinion

We have audited the consolidated financial statements of Bengal Energy Ltd. (the "Company"), which comprise:

- the consolidated statements of financial position as at March 31, 2019 and March 31, 2018
- the consolidated statements of loss and comprehensive loss for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

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

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other Information

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

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

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

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

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

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

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors'

report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group Company to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

The engagement partner on the audit resulting in this auditors' report is David Yung.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
June 20, 2019

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31		**2019**	**2018**
Assets	Notes		
Current assets:			
Cash and cash equivalents	3	$ 2,891	$ 3,904
Restricted cash		140	140
Trade and other receivables	4	2,972	4,307
Prepaid expenses and deposits		136	154
Fair value of financial instruments	17	177	-
		6,316	8,505
Exploration and evaluation assets	5	9,711	10,102
Property, plant and equipment	6	26,462	27,107
Total assets		$ 42,489	$ 45,714
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	7	$ 2,574	$ 2,232
Current portion of credit facility	9	16,482	1,934
Fair value of financial instruments	17	-	954
		19,056	5,120
Decommissioning and restoration liability	10	1,977	1,556
Credit facility	9	-	14,146
		21,033	20,822
Shareholders' equity:			
Share capital	11	98,100	98,100
Contributed surplus		7,832	7,755
Accumulated other comprehensive (loss) income		(4)	1,034
Deficit		(84,472)	(81,997)
		21,456	24,892
Total liabilities and shareholders' equity		$ 42,489	$ 45,714

Commitments (Note 20)

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31	Notes	2019	2018
Revenue			
Oil sales	13	$ 11,211	$ 10,710
Royalties		(570)	(642)
		10,641	10,068
Realized (loss) gain on financial instruments	17	(1,236)	568
Unrealized gain (loss) on financial Instruments	17	1,086	(1,661)
		10,491	8,975
Expenses			
General and administrative		2,900	2,398
Operating		3,625	3,718
Depletion and depreciation	6	1,457	2,040
Impairment	5,6	2,791	12,167
Share-based compensation		69	95
Foreign exchange loss (gain)		1,053	(26)
		11,895	20,392
Other expense			
Other		-	(124)
Finance expense	16	1,071	978
Net loss		(2,475)	(12,271)
Exchange differences on translation of foreign operations		(1,038)	(1,051)
Comprehensive loss		$ (3,513)	$ (13,322)
Loss per share - basic & diluted	14	$ (0.02)	$ (0.12)
Weighted average shares outstanding (000s) – basic and diluted	14	102,267	102,267

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)

For the years ended March 31	2019	2018
Share capital		
Balance at beginning and end of year	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of year	7,755	7,645
Share-based compensation – expensed	69	95
Share-based compensation – capitalized	8	15
Balance at end of year	7,832	7,755
Accumulated other comprehensive income (loss)		
Balance at beginning of year	1,034	2,085
Exchange differences translation of foreign operations	(1,038)	(1,051)
Balance at end of year	(4)	1,034
Deficit		
Balance at beginning of year	(81,997)	(69,726)
Net loss	(2,475)	(12,271)
Balance at end of year	(84,472)	(81,997)
Total shareholders' equity	$ 21,456	$ 24,892

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31	Notes	2019	2018
Operating activities:			
Net loss for the year		$ (2,475)	$ (12,271)
Add (deduct) non-cash items			
Depletion and depreciation		1,457	2,040
Accretion on decommissioning and restoration liability		39	37
Accretion on credit facility		129	230
Gain on disposition of petroleum and natural gas properties		-	(124)
Share-based compensation		69	95
Impairment		2,791	12,167
Unrealized (gain) loss on financial instruments		(1,086)	1,661
Unrealized foreign exchange loss (gain)		1,296	(98)
Funds from operations		2,220	3,737
Change in non-cash working capital	19	471	(110)
Net cash from operating activities		2,691	3,627
Investing activities:			
Exploration and evaluation expenditures	5	(930)	(2,277)
Petroleum and natural gas property expenditures	6	(3,416)	(1,234)
Change in non-cash working capital	19	1,161	208
Net cash used in investing activities		(3,185)	(3,303)
Financing activities:			
Repayment of credit facility	9	(176)	-
Facility extension fees	9	(132)	(95)
Change in non-cash working capital	19	(28)	(109)
Net cash used in financing activities		(336)	(204)
Net (decrease) increase in cash and cash equivalents		(830)	120
Cash and cash equivalents, beginning of year		3,904	3,903
Impact of foreign exchange on cash and cash equivalents		(183)	(119)
Cash and cash equivalents, end of year		$ 2,891	$ 3,904

See accompanying notes to the 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 consolidated financial statements (the “financial statements”) of the Company as at March 31, 2019 and 2018 and for the years then ended 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.

Bengal’s principal place of business and registered office is located at 2000, 715 5th Ave SW, Calgary, Alberta, Canada, T2P 2X6.

2. BASIS OF PREPARATION

These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”).

The financial statements were approved and authorized for issuance by the Board of Directors on June 20, 2019.

These financial statements have been prepared on a historical cost basis, except for commodity contracts as discussed in Note 17.

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.

3. CASH AND CASH EQUIVALENTS

Cash and cash equivalents include cash on hand and in banks and investments with an original maturity date of 90 days or less. Cash and cash equivalents at the end of the reporting period as shown in the statement of financial position are comprised of:

($000s)	**March 31, 2019**	**March 31, 2018**
Cash and bank balances	2,885	3,897
Short-term deposits	6	7
	2,891	3,904

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)	March 31, 2019	March 31, 2018
Due from joint venture partners	2,928	4,214
Other receivables	44	93
	2,972	4,307

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 venture partner, are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint venture 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 March 31, 2019 (March 31, 2018 - $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, 2017	20,529
Additions	1,768
Acquisition	509
Capitalized share-based compensation	7
Impairment	(12,167)
Exchange adjustments	(544)
Balance, March 31, 2018	10,102
Additions	930
Capitalized share-based compensation	4
Impairment	(894)
Exchange adjustments	(431)
Balance, March 31, 2019	9,711

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

($000s)	
ATP 732P – Tookoonooka	5,380
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,725
ATP 934 – Barrolka	1,852
Other(1)	145
Balance, March 31, 2018	10,102

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

(1) Other includes capitalized G&A, share-based compensation and foreign exchange effects on these assets denominated in a foreign currency.

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.

In Q4 fiscal 2018, the Company consolidated its ownership of ATP 934 and now owns and controls operatorship of a 100% working interest. The purchase consideration was AUS$ 311,221 cash and potential future cash payments of up to AUS$ 1,000,000, subject to certain conditions and commercial benchmarks being achieved (see Note 20).

The Company recorded an impairment charge of $12.2 million against the Company's ATP 732 asset in Q4 fiscal 2018 due to certain leases expiring that the Company had no intention of developing or renewing.

During Q1 fiscal 2019, the Company impaired $0.1 million pertaining to the carrying cost of its 10% interest in the offshore Timor Sea property, AC/RL 10. In Q2 fiscal 2019, the Company impaired $0.8 million related to an exploratory well drilled in the southwest of the Cuisinier field. Although oil was found, it was determined that the quantity was not sufficient to make the well commercial.

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

($000s)	Petroleum and natural gas properties	Other assets	Total
Cost:			
Balance, April 1, 2017	47,875	344	48,219
Additions	1,234	-	1,234
Disposals	(4,316)	-	(4,316)
Capitalized share-based compensation	8	-	8
Change in decommissioning and restoration liability	167	-	167
Exchange adjustments	(732)	-	(732)
Balance, March 31, 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

($000s)	Petroleum and natural gas properties	Other assets	Total
Accumulated depletion, depreciation and impairment losses:			
Balance, April 1, 2017	19,386	287	19,673
Depletion and depreciation	2,026	14	2,040
Disposals	(4,316)	-	(4,316)
Exchange adjustments	76	-	76
Balance, March 31, 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

($000s)			
Net carrying amount:			
At March 31, 2018	27,064	43	27,107
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.

At March 31, 2019, the Company evaluated its property, plant and equipment assets for indicators of impairment. The unsuccessful drilling efforts and negative technical revisions were the primary triggers that indicated further testing was necessary for the Cuisinier CGU.

The calculation of depletion for the year ended March 31, 2019 included $60.9 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2018 - $58.1 million).

The recoverable amount for the Cuisinier CGU was estimated at FVLCD, which is classified as a level 3 fair value measurement, based on the net present value of after-tax cash flows from proved plus probable oil and gas reserves estimated by an independent reserve evaluator. Management recognizes that all assumptions and estimates affecting the value are subject to a high degree of uncertainty. A pre-tax discount rate of 20% was applied to calculate the recoverable amount of $71.0 million. No further impairment was recorded.

During Q2 fiscal 2018, the Company disposed of petroleum and natural gas properties that had no net carrying value for nominal proceeds. The properties had an associated decommissioning liability of $124,000.

At March 31, 2018, there were no indicators of impairment or impairment reversal. As a result, no impairment or impairment reversal testing was conducted.

During fiscal 2019, the Company capitalized $0.4 million of general and administrative expense (2018 - $9.8 million.

The following forecast commodity prices were used at March 31, 2019:

Year	CADUSD Exchange Rate USD/CAD	Brent Blend Crude Oil FOB North Sea Then Current USD/bbl
2019	0.750	63.25
2020	0.770	68.50
2021	0.790	71.25
2022	0.810	73.00
2023	0.820	75.50
2024	0.825	78.00
2025	0.825	80.50
2026	0.825	83.41
2027	0.825	85.02
2028	0.825	86.66
2029+	0.825	+2.0%/yr

7. TRADE AND OTHER PAYABLES

($000s)	March 31, 2019	March 31, 2018
Trade payables	1,525	702
Accrued liabilities and other payables	1,049	1,530
	2,574	2,232

8. INCOME TAXES

The provision for income taxes differs from the amount obtained in applying the combined federal and provincial income tax rates to the loss for the year. The difference relates to the following items:

($000s) Year ended March 31	2019	2018
Loss before taxes	(2,475)	(12,271)
Statutory tax rate	27%	27%
Expected income tax recovery	(668)	(3,313)
Foreign exchange	-	(403)
Share-based compensation	19	26
Effect of change in tax rate and other	476	(308)
Other	(54)	-
Changes in unrecognized tax asset	227	3,998
Income tax recovery	-	-

The deductible temporary differences included in the Company's unrecognized deferred income tax assets are as follows:

($000s) Year ended March 31	2019	2018
Non-capital losses	50,833	46,135
Net capital losses	5,992	6,034
P&NG properties	8,901	12,983
Share issue costs	211	263
Decommissioning obligations	-	-
	65,937	65,415

The components of the Company's and its subsidiaries deferred income tax assets are as follows:

($000s) Year ended March 31	2019	2018
Property, plant and equipment	4,878	4,446
Fair value of financial instruments	53	(286)
Foreign exchange	(802)	(430)
Decommissioning obligations	(593)	(467)
Non-capital losses	(3,536)	(3,263)
	-	-

At March 31, 2019, the Company had approximately $ 26.9 million and $28.4 million of non-capital losses in Canada and Australia respectively (2018- $30.3 million and $26.8 million, respectively), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026 to 2037. The Australian non-capital losses have no term to expiry. The Company's ongoing drilling activities continue to generate deferred tax assets related to Petroleum Resource Rent Tax in its Australian subsidiary, which has not been recognized.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2019, the Company has no deferred tax liabilities in respect of these temporary differences.

9. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(1,984)
	12,386
Facility extension fees	(95)
Unrealized foreign exchange loss	2,683
Accretion	1,106
Balance, March 31, 2018	16,080
Repayment	(176)
Unrealized foreign exchange loss	581
Facility extension fees	(132)
Accretion	129
Balance, March 31, 2019	16,482

($000s)	March 31, 2019	March 31, 2018
Current portion	16,482	1,934
Non-current portion	-	14,146

In October 2014, Bengal closed its US$25.0 million secured credit facility (the "Credit Facility") with Westpac Institutional Bank ("Westpac") and placed an initial draw on November 12, 2014 of US$14.0 million. On August 25, 2016 following a US$1.5 million repayment, the Company extended the Credit Facility by 18 months to December 2018 with a borrowing base of US$15.0 million. On September 25, 2017, the Company extended the Credit Facility to December 2019 with a borrowing base of US$12.5 million. On March 5, 2018, the Credit Facility was further amended to delay the majority of principal payments into 2019. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US LIBOR plus 3.2%.

The Credit Facility is structured as a reserve-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. Under the amendment to the Credit Facility dated March 5, 2018, the Company was required to make a US$1.5 million principal payment on December 31, 2018 and a further US$5.0 million on June 30, 2019 and US$6.0 million on December 30, 2019. In addition, the Company had agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement that requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve-based review by April 30, 2019. Pursuant to these terms, the Company repaid US$131,000 during Q3 fiscal 2019.

On November 19, 2018, the Company and Westpac entered into a revised amendment agreement to the Credit Facility to defer all principal payments previously required under the March 5, 2018 amendment to February 15, 2020. This revised amendment now requires the Company to make a single payment of the outstanding amount owing on the Credit Facility. All other terms and conditions previously provided under the March 5, 2018 amendment remain in effect. There was an interest rate change from LIBOR plus 3.2% to 3.75% effective January 1, 2019. Given the repayment date of February 15, 2020, the debt has been classified as current as at March 31, 2019.

On May 29, 2019, the Company and Westpac entered into an amendment to the November 19, 2018 agreement that has the all principal payments deferred from February 15, 2020 to April 1, 2020. All previous terms under the November 19, 2018 amendment will transfer directly to the May 29, 2019 amendment.

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 March 31, 2019.

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

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

Management is in discussion with the lender to further amend the current repayment terms. 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 (see Note 17(b)).

10. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2017	1,516
Change in estimate	167
Disposals	(124)
Accretion	37
Exchange adjustments	(40)
Balance, March 31, 2018	1,556
Change in estimate	168
Additions	280
Accretion	39
Exchange adjustments	(66)
Balance, March 31, 2019	1,977

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 March 31, 2019 is approximately $2.5 million (March 31, 2018 – $2.2 million) which will be incurred between 2022 and 2048. An inflation factor of 1.78% (March 31, 2018 – 1.9%) and a risk-free discount rate of 1.79% (March 31, 2018 – 2.6%) have been applied to the decommissioning liability at March 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, 2017	68,177,796	94,151
Issued on exercise of rights offering	34,088,898	4,091
Share issue costs	-	(142)
Balance at March 31, 2018 and 2019	102,266,694	98,100

12. SHARE-BASED COMPENSATION

The Company has a share option plan for directors, officers, employees and consultants 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 three to five years and vest one-third immediately 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 on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries. 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.

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 immediately. The remaining two instalments are charged to profit or loss over their respective vesting period of one and two years respectively. For options that vest one-third each year on the first year anniversary, the fair value of the options are charged to profit and loss over the three year vesting period. 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, 2017	2,702,500	0.43
Granted	3,355,000	0.10
Forfeited	(543,853)	0.11
Expired	(911,147)	0.55
Balance, March 31, 2018	4,602,500	0.20
Granted	250,000	0.11
Expired	(750,000)	0.63
Balance, March 31, 2019	4,102,500	0.12
Exercisable, March 31, 2019	236,096	0.18

		Options Outstanding	Options Exercisable
Exercise Price	Number Outstanding	Remaining Life (years)	Number Exercisable
$0.10	2,880,000	3.25	-
$0.11	250,000	4.00	-
$0.125	25,000	3.50	-
$0.18	947,500	1.33	236,096
	4,102,500	2.85	236,096

The fair value of the options granted during fiscal 2019 and 2018 were estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

	2019	2018
Assumptions:		
Risk-free interest rate (%)	2.00	1.13 - 1.78
Expected life (years)	5	5
Expected volatility (%)(1)	95	91 - 92
Estimated forfeiture rate (%)	20	20
Weighted average fair value of options granted	$0.08	$0.07 - $0.09
Weighted average share price on date of grant	$0.11	$0.10 - $0.125

(1) Expected volatility is estimated by considering historic, average share price volatility.

The fair value of the 3,330,000 and 25,000 stock options granted during Q2 and Q3 fiscal 2018 were approximately $187,000 and $2,000 respectively.

The fair value of the 250,000 stock options granted during Q1 fiscal 2019 was approximately $16,000.

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, whereby delivery takes place through the contract period. 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.

($000s except per share amounts)

Year ended March 31	**2019**	**2018**
Net loss for the year	(2,475)	(12,271)
Weighted average number of common shares – basic and diluted	102,267	102,267
Basic and diluted loss per share	$ (0.02)	$ (0.12)

For the year ended March 31, 2019, there were 4,102,500 (March 31, 2018 - 4,602,500) options considered anti-dilutive.

15. COMPENSATION OF KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

($000s)

Year ended March 31	**2019**	**2018**
Salaries and employee benefits	982	977
Share-based compensation[(1)]	69	97
	1,051	1,074

(1) Represents the amortization of share-based compensation expense associated with the Company’s share-based compensation plans granted to key management personnel.

16. FINANCE EXPENSE

($000s)		
Year ended March 31	**2019**	**2018**
Interest income	(10)	(13)
Accretion on decommissioning and restoration liability	39	37
Letter of credit charges	8	-
Interest on Credit Facility	1,034	954
	1,071	978

17. FINANCIAL RISK MANAGEMENT

The Company has exposure to credit, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives and policies and processes for measuring and managing risk.

The Board of Directors has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. Bengal's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at March 31, 2019, Bengal's receivables consisted of $2.93 million (March 31, 2018 - $4.3 million) from joint venture partners (of which $1.0 million has been collected subsequent to year end) and $0.04 million (March 31, 2018 - $nil million) of other receivables.

Bengal has a COSPA agreement with a purchaser and has not experienced any collection problems to date.

Cash calls paid to Bengal's Australian joint venture partners are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint venture 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 March 31, 2019 (March 31, 2018 - $nil). Past due is considered greater than 90 days outstanding.

The carrying amount of accounts receivable and cash and cash equivalents and fair value of financial instruments represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at March 31, 2019 and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the year ended March 31, 2019 (March 31, 2018 – $nil). Exposure to the carrying value of its financial instruments relates to the Company's commodity-based derivatives held by Westpac Banking Corporation. Management considers the credit risk of these instruments to be adequately mitigated by the credit standing of their holder; therefore, no allowance has been established.

Cash and cash equivalents, when held, consist of cash bank balances and guaranteed investment certificates redeemable at any time. Bengal manages the credit exposure related to guaranteed investments by selecting counterparties based on credit ratings and monitors all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

(b) Liquidity risk

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, fair value of financial instruments and Credit Facility and amounted to $19.1 million at March 31, 2019 (March 31, 2018 - $19.3 million).

At March 31, 2019, the Company had a working capital deficiency of $12.7 million, including cash and short-term deposits of $2.9 million and restricted cash of $0.1 million, compared to working capital of $3.4 million at March 31, 2018. The working capital deficit of $12.7 million is primarily a result of the reclassification of the bank debt of $16.5 million to current from long term (see Note 9). Notwithstanding the bank debt reclassification, the working capital at March 31, 2019 would have been a positive $3.7 million. The Company does not anticipate any difficulty in meeting its current obligations. The Company has no available undrawn debt capacity under its Westpac Credit Facility.

The Company has significant spending commitments to be incurred by February 2021 on ATP 934P and has its US$12.4 million Credit Facility that matures in April 2020. Management is in discussions with Westpac to further extend the Credit Facility. Management anticipates that operating and capital requirements will be met out of operating cash flows in addition to alternative forms of capital raising. There can be no guarantees that the Credit Facility will be extended or that alternative forms of capital raising will be available or obtained on terms that are satisfactory to the Company. Should Westpac not further defer principal payments and the Company be unsuccessful in obtaining additional funding, there will be an adverse impact to the Company's liquidity.

The majority of the Company's oil sales are benchmarked on US Brent prices. 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 low 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 appropriate. The Company will 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 activities through fiscal 2019 and beyond.

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

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

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.

(c) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: foreign currency risk, commodity price risk and interest rate risk. The Company is exposed to market risks resulting from fluctuations in foreign exchange rates, commodity prices and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to these risks.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives US 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 risk, but has not done so to date.

The table below shows the Company's exposure in Canadian dollar equivalent to foreign currencies for its financial instruments:

($000s)	**CAD$**	**AUS$**	**US$**	**Total**
Cash and cash equivalents	85	28	2,778	2,891
Restricted cash	140	-	-	140
Trade and other receivables	13	30	2,929	2,972
Fair value of financial instruments	-	-	177	177
Trade and other payables	(240)	(2,326)	(8)	(2,574)
Credit Facility	-	-	(16,482)	(16,482)

Exchange rates as at March 31:	**2019**	**2018**
Number of CAD$ for 1 AUS$	0.95	0.99
Number of CAD$ for 1 US$	1.34	1.29

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 March 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**
April 1, 2019 – April 30, 2019	Oil - swap	5,000	73.28	73.28
				-

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	**Type of contract**	**Quantity Contracted (bbls)**	**Price floor US $/bbl**	**Price ceiling US $/bbl**
May 1, 2019 – May 31, 2019	Oil - swap	5,000	72.92	72.92

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	**Type of contract**	**Quantity Contracted (bbls)**	**Price floor US $/bbl**	**Price ceiling US $/bbl**
June 1, 2019 – June 30, 2019	Oil - swap	5,000	72.92	72.92

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	41	-	41
Non-current fair value of financial instruments	-	-	-
	41	-	41

Time period	**Type of contract**	**Quantity Contracted (bbls)**	**Price floor US $/bbl**	**Price ceiling US $/bbl**
July 1, 2019 – July 31, 2019	Oil - swap	5,000	75.03	75.03

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	60	-	60
Non-current fair value of financial instruments	-	-	-
	60	-	60

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
August 1, 2019 – August 31, 2019	Oil - swap	5,000	74.69	74.69

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	58	-	58
Non-current fair value of financial instruments	-	-	-
	58	-	58

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
September 1, 2019 – September 30, 2019	Oil - swap	5,000	74.37	74.37

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	57	-	57
Non-current fair value of financial instruments	-	-	-
	57	-	57

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
October 1, 2019 – December 31, 2019	Oil - swap	7,500	54.20	54.20
October 1, 2019 – December 31, 2019	Oil – put option	7,500	54.20	-

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(113)	18	(95)
Non-current fair value of financial instruments	-	-	-
	(113)	18	(95)

Time period	Type of contract	Quantity Contracted (bbls)	Price floor US $/bbl	Price ceiling US $/bbl
January 1, 2020 – March 31, 2020	Oil - swap	15,000	63.74	63.74

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	(26)	-	(26)
Non-current fair value of financial instruments	-	-	-
	(26)	-	(26)

Total ($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	159	18	177
Non-current fair value of financial instruments	-	-	-
	159	18	177

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$60,000 (CAD$80,100) decrease in the fair value of financial instruments at March 31, 2019, while a US $1.00 decrease would result in an increase of approximately US$60,000 (CAD$80,100) 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 March 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 dollar LIBOR rates. The Company had no interest rate derivatives at March 31, 2019.

For the year ended March 31, 2019, a 1% increase in US LIBOR would increase interest expense by $162,000.

18. CAPITAL MANAGEMENT

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to execute on its capital investment program, provide creditor and market confidence and to sustain future development of the business.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: changes in economic conditions, the risk profile of its drilling inventory, the efficiencies of past investments, the efficiencies of forecasted investments and the timing of such investments, the forecasted cash balances, the forecasted commodity prices and resulting cash flow.

In order to maintain or adjust the capital structure, the Company may from time to time issue shares (if available on reasonable terms), issue debt instruments, sell assets, farm out properties and adjust its capital spending to manage current and projected cash levels. There can be no assurance that equity financing will be available or sufficient to meet capital commitments, or for other corporate purposes, or if equity financing is available, that it will be on terms acceptable to the Company.

19. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) Year ended March 31	2019	2018
Trade and other receivables	1,335	(732)
Prepaid expenses and deposits	18	39
Trade and other payables	342	748
Effect of change in foreign exchange rates	(91)	(66)
	1,604	(11)

Attributable to:

Operating	471	(110)
Investing	1,161	208
Financing	(28)	(109)
	1,604	(11)

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

Cash interest paid and received **($000s)** **Year ended March 31**	**2019**	**2018**
Cash interest paid	730	777
Cash interest received	10	13

20. 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 kilometers of 3D seismic and three wells.

At March 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 three wells with fracs and casing	February 2021	13.4
Onshore Australia – ATP 732	Geological and geophysical studies	March 2021	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(2) Translated at March 31, 2019 at an exchange rate of AUS$1.00 = CAD$0.9473.

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

($000s) Contractual Obligations April 2019 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	737	155	311	271	-

21. SEGMENTED INFORMATION

As at March 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' salaries, 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 year ended March 31, 2019	Australia	Corporate	Total
Revenue	11,211	-	11,211
Interest revenue	9	1	10
Interest expense	1,034	-	1,034
Depletion and depreciation	1,447	10	1,457
Impairment	2,791	-	2,791
Net loss	(1,109)	(1,366)	(2, 475)
Exploration and evaluation expenditures	930	-	930
Petroleum and natural gas property expenditures	3,416	-	3,416
($000s)			
March 31, 2019			
Exploration and evaluation assets	9,711	-	9,711
Petroleum and natural gas properties	26,430	-	26,430

($000s)

For the year ended March 31, 2018

	Australia	Corporate	Total
Revenue	10,710	-	10,710
Interest revenue	12	1	13
Interest expense	954	-	954
Depletion and depreciation	2,026	14	2,040
Impairment	12,167	-	12,167
Net loss	(11,205)	(1,066)	(12,271)
Exploration and evaluation expenditures	2,277	-	2,277
Petroleum and natural gas property expenditures	1,234	-	1,234

($000s)

March 31, 2018

Exploration and evaluation assets	10,102	-	-	10,102
Petroleum and natural gas properties	27,064	-	-	27,064

22. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these financial statements, and have been applied consistently by the Company and its subsidiaries.

(a) Basis of consolidation

The financial statements incorporate the financial statements of the Company and its wholly-owned subsidiaries Bengal Energy Australia (Pty) Ltd. and Bengal Energy International Inc.

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the financial statements from the date that control commences until the date that control ceases.

The Company recognizes in the financial statements its proportionate share of the assets, liabilities, revenues and expenses of its joint operations.

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

(b) Cash and cash equivalents

Cash and cash equivalents include cash and all investments with a maturity of three months or less.

(c) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax “risk-free” rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as a finance expense. Provisions are not recognized for future operating losses.

Decommissioning and restoration liabilities

The Company’s activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

(d) Oil and natural gas exploration and evaluation expenditures

Exploration and evaluation assets ("E&E assets")

All costs incurred prior to obtaining the legal right to explore an area are expensed when incurred.

Generally, costs directly associated with the exploration and evaluation of crude oil and natural gas reserves are initially capitalized. Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability have not yet been demonstrated. These costs generally include unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, drilling and completion costs and capitalized decommissioning costs.

Costs are held in exploration and evaluation assets until the technical feasibility and commercial viability of the project is established. Amounts are generally reclassified to petroleum and natural gas properties once probable reserves have been assigned to the field. If probable reserves have not been established through the completion of exploration and evaluation activities and there are no future plans for activity in that field, then the exploration and evaluation expenditures are determined to be impaired and the amounts are charged to profit or loss.

(e) Petroleum and natural gas properties

Carrying value

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as petroleum and natural gas properties in the specific asset to which they relate. Petroleum and natural gas properties are stated at cost less accumulated depreciation and depletion and accumulated impairment losses. The initial cost of a petroleum and natural gas property is comprised of its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given up to acquire the asset.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depletion and depreciation

The net book value of producing assets are depleted on a field-by-field basis using the unit of production method with reference to the ratio of production in the year to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis.

Other assets are depreciated on a declining basis at rates ranging from 20% to 30% per annum.

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized as separate line items in profit or loss.

(f) Impairment

E&E assets and petroleum and natural gas properties

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to petroleum and natural gas properties. For the purpose of impairment testing, E&E assets are grouped by concession or production field with other E&E assets belonging to the same concession or production field. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit or loss. Recoverable amount is determined as the higher of the value in use or fair value less costs to sell.

At the end of each reporting period, the Company reviews the petroleum and natural gas properties for circumstances that indicate that the assets may be impaired. Assets are grouped together into cash generating units ("CGU"s) for the purpose of impairment testing, which is the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of future cash flows expected to be derived from the production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down. Consideration is given to acquisition metrics or recent transactions completed on similar assets to those contained with the relevant CGU.

When the recoverable amount is less than the carrying amount, the asset or CGU is impaired. The impairment loss is recognized as an expense in profit or loss.

At the end of each subsequent reporting period these impairments are assessed for indicators of impairment reversal. Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss have been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized in profit or loss.

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

(g) Financial instruments

The Company adopted IFRS 9 with a date of initial application as of April 1, 2018, the date at which all IFRS 9 classification and measurement is required to be implemented. The Company retrospectively adopted the standard and elected not to restate comparative information. There were no material changes in the measurement and carrying values of the Company's financial instruments as a result of the adoption. IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI"), or fair value through profit or loss ("FVTPL"). IFRS 9 eliminates the previous IFRS 39 categories of held to maturity investments, loans and receivables, other financial liabilities and available for sale financial assets. The classification of financial assets under IFRS 9 is based on the business model in which a financial asset is managed and the nature of its contractual cash flow characteristics. Embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9; the entire hybrid contract is assessed for classification and measurement.

IFRS 9 replaces the 'incurred credit loss model' in IAS 39 with an 'expected credit loss' model. The new impairment model applies to financial assets measured at amortized cost, a lease receivable, a contract asset or a loan commitment and a financial guarantee contract. Under IFRS 9, credit losses are recognized earlier than under IAS 39; it is no longer necessary for a credit event to have occurred before credit losses are recognised.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at April 1, 2018 for each class of the Company's financial assets and financial liabilities. The Company has no contract assets or financial instruments measured at FVOCI. The transition to IFRS 9 did not result in changes to the original carrying amount of the following financial instruments as compared to IAS 39.

Measurement Category

Financial Instrument	**IAS 39**	**IFRS 9**
Cash and cash equivalents	Fair value	Amortised cost
Trade and other receivables	Amortised cost	Amortised cost
Trade and other payables	Amortised cost	Amortised cost
Long-term debt	Amortised cost	Amortised cost
Derivative contracts	Fair value	FVTPL

Derivative financial instruments

The Company enters into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company does not designate its financial derivative contracts as effective accounting hedges and therefore will not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all derivative contracts are classified as FVTPL and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein will be recognized immediately in profit or loss.

The Company may enter into physical delivery sales contracts for the purposes of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and will not be recorded at fair value on the statement of financial position. Settlements on these physical delivery contracts will be recognized in petroleum and natural gas revenue in the period of settlement.

Fair value

The fair value of financial instruments that are actively traded in organized financial markets is determined by reference to quoted market bid prices at the valuation date. For financial instruments that have no active market, fair value is determined using valuation techniques including the use of recent arm's length market transactions, reference to the current market value of equivalent financial instruments and discounted cash flow analysis.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects.

(h) Foreign currency translation

The financial statements are presented in Canadian dollars, which is the Canadian parent entity's functional and presentation currency; the functional currency of the Indian subsidiary is US dollars and the functional currency of the Australian subsidiary is Australian dollars. For the accounts of foreign operations, assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the foreign operations are included in accumulated other comprehensive income, a component of equity. Foreign currency transactions are translated into the legal entity's functional currency at the exchange rate in effect at the transaction; and any gains or losses are recorded in profit or loss.

(i) Share-based compensation

The Company accounts for share-based compensation granted to directors, officers, employees and consultants using the Black-Scholes option-pricing model to determine the fair value of the options at grant date. An estimated forfeiture rate is incorporated into the fair value calculated and adjusted to reflect the actual number of options that vest. Share-based compensation expense is recorded and reflected as share-based compensation expense over the vesting period with a corresponding amount reflected in contributed surplus. At exercise, the associated amounts previously recorded as contributed surplus are reclassified to share capital.

(j) Revenue recognition

In April 2016, the IASB issued its final amendments to IFRS 15 Revenue from Contracts with Customers ("IFRS 15"), which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue; at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted.

The Company adopted the standard for its fiscal year commencing April 1, 2018, using the retrospective approach. Based on the Company's review of contracts with customers, there were no adjustments made to the April 1, 2018 opening statement of financial position.

The nature of the Company's performance obligations, including roles as third parties and partners, are evaluated to determine if the Company acts as a principal. The Company recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if the Company acts in the capacity of an agent rather than as a principal.

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 additional disclosures required by IFRS 15 are detailed in Note 13.

(k) Per share amounts

Basic per share amounts are computed by dividing net income (loss) by the weighted average number of common shares outstanding for the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options or other dilutive instruments were exercised into common shares. The treasury stock method assumes that any proceeds upon the exercise of dilutive instruments, including remaining unamortized compensation costs, would be used to purchase common shares at the average market price of the common shares during the period.

(l) Income taxes

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustments to tax payable in respect of previous years.

Deferred tax is recognized providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(m) Finance income and expenses

Finance income consists of interest earned on term deposits. Finance expenses include letter of credit charges, interest on the Credit Facility, and accretion of the discount on decommissioning obligations.

(n) Determination of fair value

A number of the Company's accounting policies and disclosures required the determination of fair value, both for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

Fair Value Hierarchy

Financial instruments that are measured subsequent to initial recognition at fair value are grouped into three categories based on the degree to which fair value is observable:

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

Level 2 - Valuations are based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; including forward prices for commodities, time value and volatility factors which can be substantially observed or corroborated in the marketplace;

Level 3 - Inputs that are not based on observable data for the asset or liability.

The Company's financial instruments comprise cash and cash equivalents, restricted cash, trade and other receivables, trade and other payables, Credit Facility and derivatives.

The Company's policy is to recognize transfers in and out of the fair value hierarchy as of the date of the event or change in circumstances that caused the transfer. There were no such transfers during the period.

Fair values have been determined for measurement and disclosure purposes as follows:

i) **Cash and cash equivalents, restricted cash, trade and other receivables, trade and other payables**

The fair values of these financial instruments approximate their carrying amounts due to their short-term maturity.

ii) **Credit facility**

The fair value of the Company's Credit Facility approximates its carrying value as it bears interest at floating rates and the applicable margin is indicative of the Company's current credit risk.

iii) Derivatives

The Company's commodity contracts (swaps and put options) are measured at level 2 of the fair value hierarchy. The fair value of the swap component is determined by discounting the difference between the contracted prices and published forward price curves as at the period end date, using the remaining contracted oil volumes and a risk-free interest rate. The fair value of puts are based on option models that use publish information with respect to volatility, prices and interest rates.

(o) New standards and interpretations not yet adopted

Standards that are issued but not yet effective and that the Company reasonably expects to be applicable at a future date are listed below.

IFRS 16 Leases

In January 2016, the IASB issued IFRS 16 *Leases* ("IFRS 16"). This standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than 12 months. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The Company's assessment of the impact of the adoption of the standard is still in progress.

23. MANAGEMENT JUDGMENTS AND ESTIMATES

The financial statements have been prepared on a going concern basis. The going concern basis of presentation 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.

Significant doubt about the Company's ability to continue as a going concern would exist when relevant conditions and events, considered in the aggregate, indicate that it is probable that the Company will not be able to meet its obligations as they become due for a period of at least, but not limited to, twelve months from the balance sheet date. When the Company identifies conditions or events that raise potential for significant doubt about its ability to continue as a going concern, the Company considers whether its plans that are intended to mitigate those relevant conditions or events will alleviate the potential significant doubt. The mitigating effect of management's plans are considered to the extent that (i) it is probable that the plans will be effectively implemented and, if so, (ii) it is probable that the plans will mitigate the conditions or events that raise significant doubt about the Company's ability to continue as a going concern. After considering its plans to mitigate the going concern risk, management has concluded that there are no material uncertainties related to events or conditions that may cast significant doubt upon the Company's ability to continue as a going concern. Furthermore, the estimates made by management in reaching this conclusion are based on information available as of the date these financial statements were authorized for issuance.

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. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are out-lined below.

(a) Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of cash-generating units

Bengal's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Recognition of deferred income tax assets

The recognition of deferred income tax assets requires judgments regarding the likelihood and applicability of future income tax deductions. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and ability to apply income tax deductions.

(b) Key sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of assets, and impairment charges and reversal will affect profit or loss.

Reserves

The estimate of petroleum and natural gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's development and production assets has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

Liquidity

The Company has a working capital deficiency as at March 31, 2019 of $12.7 million, including $16.5 million outstanding on its Credit Faculty, and incurred a loss for the year ended March 31, 2019 of $2.6 million. The Credit Facility expires on February 15, 2020 and is classified as current as at March 31, 2019 (refer to Note 9). Subsequent to year end, the Company and the lender entered into a revised amendment agreement to extend the facility to April 1, 2020.

Management is in discussion with the lender to further amend the current repayment terms. 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.

CORPORATE INFORMATION

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Robert D. Steele
Ian J. Towers (Chairman)
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Bruce Allford, Secretary

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