International Exploration & Production

2020 Annual Report
Twelve Months Ended
March 31, 2020

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

During fiscal 2020, Bengal Energy Ltd. ("Bengal" or the "Company") has been active across numerous fronts. This included focused geological and geophysical efforts to accelerate and better understand the opportunities for growth on both the Cuisinier asset as well as the balance of the Bengal portfolio. Tie-in of the three successful oil wells drilled in the 2018 campaign and the hydraulic stimulation of two additional oil wells at Cuisinier occurred during the fiscal year 2020. In addition, the Company remains 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, Bengal has deferred further development drilling to 2021 in light of low oil prices. The Company anticipates start up of the planned waterflood pilot on our C24 well in the third quarter of calendar 2020 and will participate in hydraulic stimulation projects on other wells in the Cuisinier oil pool

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 forecast to be undersupplied in the medium term and expected to remain so for the next 5-10 years. Although current spot pricing is in the range of AUS$5.50 per mcf, these market economics have resulted in the projection of natural gas prices forecast to range between AUS$10-$12 per mcf as we approach 2024. 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, 2020 averaged 279 bopd, a decrease of 6% over fiscal 2019 due to natural production declines. Bengal's independently evaluated Proved Plus Probable ("2P") reserves during the fiscal year ended March 31, 2020 is 5,855 Mbbls and Proved reserves are 2,216 Mbbls. The net present value (NPV10, before tax) of Bengal's 2P reserves are $96.4 million, or $0.94 per share. The Company's 2P net asset value before tax, which deducts net debt from the net present value (NPV10, before tax), is $79.7 million or $0.78 per share. The 2P after tax net asset value is $56.4 million and $0.55 per share. The net present value (NPV10, before tax) of Bengal's Proved reserves are $36.2 million, or $0.35 per share. The Company's Proved net asset value before tax, deducting net debt from the net present value (NPV10, before tax), is $19.5 million or $0.19 per share. The Proved after tax net asset value is $13.6 million or $0.13 per share. These decreases in value over the prior year are primarily a result of much lower forecast crude oil prices. As global oil prices recover, we remain confident in our ability to grow further 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.

During the year Bengal acquired a 100% interest in four Production Licences (PL's) and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market. These currently non- producing PLs are highly compatible with and in close proximity to ATP 934 (100% WI) and bring a much reduced risk profile to the Bengal portfolio. In addition, we have commenced discussions with a third party who have an interest in farming in on our exploration asset, ATP 934. 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 gradually strengthened from its abrupt collapse in March in the face of both the onset of the COVID-19 pandemic and the oil price war led by Saudi Arabia and Russia. Natural gas prices have also been negatively affected due to the decreased demand for LNG exports to Asia and more gas being available for the domestic market. We are encouraged by the medium term bullish outlook for natural gas demand for eastern Australia and optimistic on the multiple egress and marketing opportunities available to optimize ATP 934 natural gas pricing and returns.

Management continues to discuss its secured credit facility (the "Credit Facility") with Westpac Institutional Bank, (the lender) an opportunity to lengthen the term of the current facility particularly in light of the recent acquisition which has the potential to both increase reserves and improve cash flow. There would be an adverse impact on the Company's liquidity and its ability to continue as a going concern should it be unsuccessful in negotiating an amendment and deferral of principal payments to the Credit Facility. The Credit Facility now has an expiry date of October 30 2020 and continues to provide a borrowing base of US$ 12.4 million, of which the full amount is currently drawn. The Company continues to benefit from its hedging program, which has approximately 50% of production attracting prices of nearly US$ 60/bbl.

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. The Bengal share price along with that of most other junior and intermediate public oil companies has been severely affected by the actions of Saudi Arabia and Russia in oversupplying the oil market in the face of decreasing global demand from the onset of the COVID-19 pandemic. However, management remains confident of 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, 2020 and 2019

Bengal
ENERGY LTD.

International exploration & production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2020 and 2019

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 and twelve months ended March 31, 2020.

This MD&A dated June 25, 2020 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2020 and 2019. 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 Bengal Energy (Australia) Pty Ltd. ("Bengal Australia"), 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, 2020 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2020 may be referred to as "fourth quarter of fiscal 2020", "Q4 fiscal 2020" "Q4 FY 2020", "current quarter", and "the quarter". The comparative three months ended March 31, 2019, may be referred to as "fourth quarter of fiscal 2019", "Q4 fiscal 2019" "Q4 FY 2019", and "prior year's quarter". The year ended March 31, 2020, may be referred to as "fiscal 2020", "current year", and "the year". The comparative year ended March 31, 2019, may be referred to as "the previous year", "prior year", and "fiscal 2019".

FOURTH QUARTER FISCAL 2020 SUMMARY

Financial Summary:

- **Sales Revenue** – Crude oil sales revenue was $1.1 million in the fourth quarter of fiscal 2020, which is 59% lower than the $2.7 million recorded in Q4 fiscal 2019. Full year fiscal 2020 sales revenue was $8.1 million compared to $11.2 million for the full year fiscal 2019. The lower full year performance in fiscal 2020 compared to fiscal 2019 was due primarily to the significant decline in US Brent at the end of March 2020 due to the Saudi/Russian price war coupled with demand destruction associated with the COVID-19 pandemic which impacted both sales revenue and the value of pipeline oil.
- **Hedging** – The Company's Credit Facility (as defined herein) requires that a minimum of 50% of oil production be hedged forward by a minimum of 12 months. During the month of March 2020, when the Company would normally place the required hedges for the following year, forward price volatility was so impacted by COVID-19 and global oil price decline due to the Saudi/Russian price war that Westpac Banking Corporation's ("Westpac") hedging group was not taking any orders on any forward contracts or options and Westpac was not requiring the Company to enter into hedges that would lock in low prices. As the hedging requirement is not a covenant, no waiver was required and the Banks acknowledgement was sufficient for the Company to be compliant. Once oil price markets are less volatile and Westpac resumes taking orders on forward contracts and options, the Company intends to place the appropriate hedges on its production. At year-end fiscal 2020, the realized gain on financial instruments was $0.5 million while an unrealized gain on financial instruments of $1.3 million was recorded. The quarter ended March 31, 2020 had hedges in place at US$63.74/bbl while the two subsequent quarters have a portion of expected production hedged at approximately US$59/bbl and US$56/bbl respectively. For the quarter ending December 31, 2020, 4,200 bbls of production, representing 50% of the expected production of 8,400 bbls in Q3 FY 2021, has been hedged at approximately US$58/bbl.
- **Funds generated (used in) Operations**[1] – Bengal had funds used in operations of $0.9 million during Q4 fiscal 2020 compared to $0.8 million of funds generated from operations in Q4 fiscal 2019. For the full year fiscal 2020, the Company generated funds from operations of $0.5 million, down from $2.2 million of funds from operations in fiscal 2019. The primary reason for the decrease in funds from operations during fiscal 2020 as compared to fiscal 2019 was the impact of lower commodity pricing in Q4 fiscal 2020.
- **Net loss** – Bengal reported a net loss of $2.2 million for the current quarter compared to a net loss of $2.1 million in the fourth quarter of fiscal 2019. For the full year fiscal 2020, the Company reported a net

[1] See "Non-IFRS Measurements" on page 20 of this MD&A

loss of $2.9 million compared to fiscal 2019 net loss of $2.6 million. Despite the lower price environment in Q4 fiscal 2020, the Company was able to substantially mitigate the financial impact with a cost reduction program and strong hedging strategy.

- **Adjusted Net Income[2] –** Bengal reported an adjusted net loss of $1.1 million for the current quarter and $1.1 million for the full year fiscal 2020. 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 23,117 bbls of light crude oil, which is a 9% decline from the 25,303 bbls produced in the fourth quarter of fiscal 2019. The current quarter production averaged 254 bbls/day compared to 281 bbls/day produced in the fourth quarter of fiscal 2019. Full year fiscal 2020 saw total production of 102,230 compared to 108,731 for full year fiscal 2019. The full year fiscal 2020 production per day averaged 279 bbls compared to 298 bbls/day for the full year fiscal 2019. Normal production declines and lower than expected results from the 2019 drilling campaign are the reasons for the reduction in production year over year.
- **Capital Expenditures** – Bengal commenced its five well development drilling program in the fourth quarter of fiscal 2019. The drilling program was completed at the end of Q2 FY 2020. The remaining capital expenditure required for this program of $2.0 million was incurred during fiscal 2020. The waterflood pilot, originally planned for Q3 FY 2020 and delayed due to engineering and equipment issues, is now expected to commence in Q2 fiscal 2021. Due to COVID-19, the 2020 drilling campaign has been postponed until 2021. There are no other capital expenditures expected during fiscal 2021. Subsequent to year end fiscal 2020, the Company negotiated a reduction in the commitment liability for Authority to Prospect ("ATP") 934 from AUS$12.3MM to AUS$1.2MM by relinquishing a portion of ATP 934 block.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Significant Economic Developments

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. In addition, global commodity prices have declined significantly due to disputes between major oil producing countries combined with the negative impact to oil demand from the COVID-19 pandemic. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The current challenging economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgements made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

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, Petroleum Lease ("PL") 303 Cuisinier, ATP 934 Barrolka, ATP 732 Tookoonooka, and four recently acquired petroleum licenses are situated within an area of the Cooper Basin that is well served with production infrastructure and take-away capacity for produced crude oil and natural gas. Still in early stages in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal and economic environment in which to operate, and a favourable royalty regime for oil and gas production.

Under the State of Queensland Regulatory process, ATPs are granted by the State generally for a period of

[2] See "Non-IFRS Measurements" on page 20 of this MD&A

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. In the case of ATP 752, with the producing Cuisinier Oil Field offsetting and oil shows in the Murta zone as well as the deeper Jurassic Birkhead zone in the Hudson 1, Koki 1 and Barta 1 wells previously drilled and abandoned and the evidence of structural continuity from the 3 D seismic control acquired over the last few years applications for PCA's 205 and 206 were made on the Barta block and approved by the Queensland regulatory authority. These applications include a commercial viability report that indicates the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize the resource. Similarly application was made and approved for PCA 155 on the Wompi block and approved. These PCA's remain a part of the ATP until expiry. If a discovery of oil or gas is made, an application for a petroleum lease is made to allow for production. PLs are granted for up to a thirty-year term. Bengal has two PLs on the former ATP 752 Barta block, PL 303 and PL 1028, in addition to three PCAs, PCA 206, 207 Barta West and PCA 155 Wompi block-Nubba/Yilgarn. Bengal also acquired four PLs adjacent to ATP 934 in Q2 FY 2020.

<u>**AUSTRALIA – Cooper Basin, Queensland**</u>

PL303 and PL 1028 Cuisinier (controlling permit ATP 752) (30.357% WI)

The Cuisinier 29 well is on production from the newly discovered DC-50 zone. After initial decline the well has stabilized at approximately 100 bbls/d of light crude (30 bbls/d net).

Planning and drilling location selection for the 2020 multi-well development and appraisal drilling campaign has been deferred due to the COVID 19 pandemic and exacerbated by current low oil prices. Timing of restarting the campaign will be re-assessed in future periods based on pricing and financial conditions at that time.

A pilot reservoir pressure maintenance scheme (water flood pilot) is planned to commence injection during Q3 of calendar 2020. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier 24 well. The broad nature of the Cuisinier structure combined with variable flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to increase production in up to four offsetting wells. In addition, if expected results are achieved, the program is expected to also support and enable future water flood expansion phases currently in the initial planning stages. Apart from increased oil recovery in the offsetting wells, another major benefit is reduction in produced water treatment tariffs. These tariffs are currently incurred as produced water is exported and treated at the Cook facility. The tariff structure is a tiered volume based arrangement; the water injection scheme would allow the joint venture to reduce the overall operating cost for Cuisinier oil.

PCA 155 Nubba/Yilgarn, (controlling permit ATP 752, Wompi Block) (38.08% WI)

The Company and joint venture partners are planning to conduct an extended production test on the Nubba gas discovery well. Initially planned for Q4 calendar 2019, the project is now delayed until there is certainty over a tie in point that can be accessed at a reasonable connection cost. Plans to tie in the well are subject to commercial flow rates and gas reserves being achieved, but otherwise not expected until 2022.

ATP 934 Barrolka (100% WI)

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

Discussions are ongoing with a third party who have an interest in farming-in on a portion of this block, supporting the next phase of exploration and thereby further de-risking the natural gas potential of the permit. Management believes this will progress to a firm agreement imminently.

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

As announced in the Bengal press release of September 12, 2019, the Company has acquired a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market. These non-producing PLs are highly compatible with and in close proximity to ATP 934. The Company obtained ownership of the respective PLs in Q2 FY 2020 subject to applicable regulatory approvals. Bengal continues to integrate subsurface data from the PLs to enhance the Company's understanding of ATP 934 and to finalize the selection of exploration and appraisal drilling locations and completion programs on selected wells.

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

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

ATP 732 Tookoonooka (100% WI)

In June 2019, the Company applied for an amendment to the Later Work Program (LWP) for the third term of ATP 732 permit, On October 22, 2019, the Company received approval from the Queensland regulatory authority for an amended LWP for the third, four-year term commencing April 1, 2019 to March 31, 2023. The approved LWP was revised to minimum activities of reprocessing seismic and inversion work with an estimated cost of $50K and geological and geophysical investigation at an estimated cost of $50K during the four-year term.

Business Development

During the quarter, the Company engaged in early stage, confidential and non-binding discussions with a number of third parties respecting potential business development opportunities, including possible business combination transactions expected to assist in reducing combined costs, increasing scale and advancing external financing options. Following the period, such early stage discussions have continued, however unfavourable and volatile market conditions have posed a material challenge to advancing such discussions. The Company cautions that all discussions are preliminary and non-binding and there are no assurances that such discussions will advance or that any transaction will be pursued or ultimately be undertaken.

Subsequent Events

Subsequent to the fiscal year ended on March 31, 2020, on April 24, 2020, the Company received regulatory approval for the special amendment of the initial work program on ATP 934 which reduces the total commitment from $12.3 million to $1.2 million. The Company has no further expenditure commitments on the permit before February 28, 2021 when the permit is up for renewal. As a condition of the approval, the Company agreed to relinquish an additional 17% of the permit in addition to the 33% mandatory relinquishment for a total of 50% (240 sub-blocks) of the acreage at the end of the first term on the permit. The acreage subject to the 50% relinquishment was determined by Bengal and consisted of the least prospective land from a technical perspective and with the most challenging access conditions under the terms of the existing Environmental Authority granted by the regulator. At March 31, 2020, ATP 934 was evaluated for any impairment triggers according to International Accounting Standards (IAS) 36 and no impairment triggers were uncovered.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)	Three months ended March 31				Twelve months ended March 31			
		2020		2019		2020		2019
Oil revenue	$	1,140	$	2,667	$	8,103	$	11,211
Operating netback[(1)]	$	249	$	1,944	$	4,547	$	5,780
Cash from operations	$	27	$	635	$	1,129	$	2,691
Funds from (used in) operations[(2)]	$	(849)	$	842	$	461	$	2,220
Per share ($) (basic and diluted)	$	(0.01)	$	0.01	$	0.00	$	0.02
Net loss	$	(2,196)	$	(2,144)	$	(2,896)	$	(2,475)
Per share ($) (basic and diluted)	$	(0.02)	$	(0.02)	$	(0.03)	$	(0.03)
Adjusted net income (loss)[(3)]	$	(1,111)	$	397	$	(1,125)	$	525
Per share ($) (basic and diluted)	$	(0.01)	$	0.00	$	(0.01)	$	0.01
Capital expenditures	$	(68)	$	2,473	$	2,035	$	4,346
Oil volumes (bbl/d)		254		281		279		298
Operating netback [(1)]($/bbl)	$	10.77	$	76.82	$	44.47	$	53.16

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating netback per bbl is calculated by dividing revenue (including realized gain (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found on page 8 of this MD&A.

(2) Funds from (used in) 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 fiscal year. Funds from (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) 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 21 of this MD&A.

(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 21 of this MD&A.

(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 2020	Three months ended March 31 2019	Twelve months ended March 31 2020	Twelve months ended March 31 2019
Oil production (bbls/d)	254	281	279	298
Oil production (bbls)	23,117	25,303	102,230	108,731

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 2020	Three months ended March 31 2019	Twelve months ended March 31 2020	Twelve months ended March 31 2019
	Oil lifting				
	Volume (000s bbls)	26.7	27.2	104.6	119.7
	Weighted average price ($US/bbl)	58.35	66.18	65.37	73.83
A.	Sales ($000's)	2,337	2,412	9,378	12,070
	Pipeline oil				
	Volume (000s bbls), change	(3.5)	(1.9)	(2.4)	(11.0)
	Price ($US/bbl), change	(39.80)	18.67	(49.22)	8.62
B.	Net sales ($000's)	(1,197)	255	(1,275)	(859)
A.+B.	Total oil sales ($000s)	1,140	2,667	8,103	11,211

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

The COVID-19 pandemic and the Saudi/Russian pricing war had a significant impact on the realized revenue for both the full year fiscal 2020 and particularly the Q4 fiscal 2020 results. The most prominent impact was on the valuation of Bengal's pipeline oil. At the end of Q3 FY 2020 the pipeline oil was valued using a US Brent price of $69.56/bbl. At the end of Q4 fiscal 2020, pipeline oil was valued at US Brent $29.76, a 57% decline in price valuation. When combined with a volume reduction in pipeline oil of 3,549 bbls, the value of our pipeline oil fell by $1.2 million reducing the Company's overall realized sales revenue down to $1.1 million for the current quarter. The corresponding decline on full year realized sales revenue was a $1.3 million decline in pipeline valuation which reduced Bengal's full year realized sales revenue to $8.1 million.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Brent oil ($/bbl)	67.59	84.02	81.37	91.90
Brent oil (US$/bbl)	50.44	63.17	61.18	70.15
Number of CAD$ for 1 AUS$	0.88	0.95	0.91	0.96
Number of CAD$ for 1 US$	1.34	1.33	1.33	1.31

($000s)

Operating netbacks

	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Oil sales	1,140	2,667	8,103	11,211
Realized (loss) gain on financial instruments	268	(90)	533	(1,236)
Royalties	(259)	(59)	(316)	(570)
Operating expenses	(900)	(574)	(3,773)	(3,625)
Operating netback	249	1,944	4,547	5,780
($/bbl)				
Oil sales	49.31	105.40	79.26	103.11
Realized (loss) gain on financial instruments	11.59	(3.56)	5.21	(11.37)
Royalties	(11.20)	(2.33)	(3.09)	(5.24)
Operating expenses	(38.93)	(22.69)	(36.91)	(33.34)
Operating netback	10.77	76.82	44.47	53.16

Operating netbacks were also seriously affected by the COVID-19 pandemic and the Saudi/Russian oil price war. In Q4 fiscal 2020, operating netbacks were $0.2 million or $10.77/bbl compared to Q4 fiscal 2019 at $1.9 million or $76.82/bbl. The primary reason for the decline in operating netbacks during the current quarter compared to Q4 fiscal 2019 was the collapse in oil commodity price towards the end of March which resulted in the Company realising sales revenue of only $1.1 million. For the full year fiscal 2020, operating netbacks were $4.5 million or $44.47/ bbl. The realized gain on financial instruments of $0.3 million in Q4 fiscal 2020 and $0.5 million for the full year fiscal 2020 is due primarily to the US$ 60/bbl hedges in the current quarter. Royalties have been calculated to be 3.09% of oil sales for full year fiscal 2020 as compared to 5% for the full year fiscal 2019 due to higher operating expenses in fiscal 2020. The increased royalty expense in Q4 fiscal 2020 is due to a year to date adjustment made by the operator during the current quarter, to reflect the annual fiscal 2020 reduced royalty expense. Comparative operating expenses for fiscal 2020 were higher versus Q4 fiscal 2019 and full year fiscal 2019 due to the Company's realization of credits from the joint venture audit in fiscal 2019. Due to the COVID-19 pandemic the company did not complete the fiscal 2020 JV audit at year end and now expects to complete the fiscal 2020 joint venture audit of operating expenses during Q2 FY 2021.

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. However, due to the COVID-19 pandemic, when the Company would normally place the required hedges for the following year during Q4 of the fiscal year, forward price volatility was so impacted by COVID and oil price decline due to the Saudi/Russian price war that Westpac's hedging group was not taking any orders on any forward contracts or options. Once oil price markets are less volatile and Westpac resumes taking orders on forward contracts and options, the Company may place the appropriate hedges on its 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, 2020, 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, 2020 – April 30, 2020	Oil - swap	5,000	59.49	59.49
				-

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	233	-	233
Non-current fair value of financial instruments	-	-	-
	233	-	233

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

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	209	-	209
Non-current fair value of financial instruments	-	-	-
	209	-	209

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

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	188	-	188
Non-current fair value of financial instruments	-	-	-
	188	-	188

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

($000s)	**Oil – swap**	**Oil – put**	**Total**
Current fair value of financial instruments	157	-	157
Non-current fair value of financial instruments	-	-	-
	157	-	157

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	146	-	146
Non-current fair value of financial instruments	-	-	-
	146	-	146

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	139	-	139
Non-current fair value of financial instruments	-	-	-
	139	-	139

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	130	-	130
Non-current fair value of financial instruments	-	-	-
	130	-	130

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	125	-	125
Non-current fair value of financial instruments	-	-	-
	125	-	125

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	120	-	120
Non-current fair value of financial instruments	-	-	-
	120	-	120

Total

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	1,447	-	1,447
Non-current fair value of financial instruments	-	-	-
	1,447	-	1,447

The fair value of the financial contracts outstanding as at March 31, 2020 is $1.4 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, 2020, the derivative commodity contracts resulted in a realized gain of $0.5 million (March 31, 2019 – loss of $1.2 million) and an unrealized gain of $1.3 million (March 31, 2019 – gain of $1.1 million).

Royalties

Royalties

	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Royalty expense ($000s)	259	59	316	570
$/bbl	11.20	2.33	3.09	5.24
% of revenue	23	2	4	5

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.

Royalties have been calculated to be 3.9% of oil sales for full year fiscal 2020 as compared to 5% for the full year fiscal 2019 due to higher operating expenses in fiscal 2020. The increased royalty expense in Q4 fiscal 2020 is due to a year to date adjustment made by the operator during the current quarter, to reflect the annual fiscal 2020 royalty expense.

Operating Expenses

($000s) Operating expenses	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Production	251	(231)	792	307
Transportation	649	805	2,981	3,318
	900	574	3,773	3,625
Production - $/bbl	10.86	(9.13)	7.75	2.82
Transportation - $/bbl	28.07	31.81	29.16	30.52
	38.93	22.68	36.91	33.34

Comparative operating expenses for Q4 fiscal 2020 and full year fiscal 2020 were higher versus Q4 fiscal 2019 and full year fiscal 2019 due to the Company's realization of credits from the joint venture audit in fiscal 2019. Due to the COVID-19 pandemic the company did not complete the fiscal 2020 joint venture audit at year end and now expects to complete the fiscal 2020 joint venture audit of operating expenses during Q2 FY 2021.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Total G&A	806	842	3,589	3,286
Capitalized G&A	153	(36)	(286)	(386)
Net G&A	959	806	3,303	2,900

Net G&A expenses in the fourth quarter fiscal 2020 were $1.0 million as compared to $0.8 million for the Q4 fiscal 2019. The full year fiscal 2020 saw net G&A expense at $3.3 million compared to $2.9 million for the full year fiscal 2019. The increase of $400K in net G&A expense for the full year fiscal 2020 is due to a lower amount of activity by staff and contractors that was charged to capital projects and an increase in third party consulting assisting the Company with potential strategic alternatives.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Expensed share-based compensation	6	13	28	69
Capitalized share-based compensation	-	1	1	8
	6	14	29	77

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

Depletion and Depreciation (DD&A)

($000s) DD&A	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Petroleum and natural gas properties	188	370	1,343	1,446
Other assets	2	3	7	11
Right-of-use assets	12	-	47	-
	202	373	1,397	1,457
Petroleum and natural gas properties - $/bbl	8.13	14.62	13.14	13.30

The Company's proved plus probable (2P) reserve volumes at March 31, 2020, decreased 175,000 bbls compared to March 31, 2019. In addition, capital costs to develop 2P reserves at March 31, 2020, was $59.7 million compared to $60.9 million at March 31, 2019.

Production in Q4 fiscal 2020 was 23,117 bbls compared with 25,303 bbls in Q4 fiscal 2019. These amounts coupled with the impairment charge in Q4 (as discussed below) resulted in lower depletion for Q4 fiscal 2020, compared to the comparative period.

Production for full year fiscal 2020 was 102,230 bbls compared to 108,731 bbls for the previous year, also contributing to a lower depletion rate for fiscal 2020.

Impairment

($000s) Impairment expense	Three months ended March 31		Twelve months ended March 31	
	2020	2019	2020	2019
Exploration and evaluation assets	-	-	10	885
Petroleum and natural gas properties	626	1,906	636	1,906
	626	1,906	646	2,791

As at March 31, 2020, the Company concluded that there were no triggers for impairment on its E&E assets.

During Q4 fiscal 2020, the Company took an impairment charge of $0.6 million due to one development well, Cuisinier-27, deemed to be uneconomic following evaluation of the results of the five well drilling program. At March 31, 2020, the company evaluated its petroleum and natural gas properties for indicators of impairment. Due to industry and market conditions, especially the decline in crude oil prices, the Company identified that impairment triggers were present at March 31, 2020. The Company performed an impairment test but no adjustment was required. The impairment test compared the carrying amount of the Cuisinier CGU to the fair value less costs of disposal (FVLCD) value, 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, discounted at 10% to 30% depending on the various categories of reserves. Notwithstanding there was no additional impairment recognized, other than with respect to the Cuisinier 27 well, there is a reasonable possibility that the determination of a recoverable amount could result in an impairment in future periods, if commodity prices and/or discount rates applied to various categories of reserves are adversely impacted by market conditions.

Finance Expense

($000s) Finance expense	Three months ended March 31 2020	2019	Twelve months ended March 31 2020	2019
Interest income	(2)	(1)	(4)	(10)
Accretion expense on decommissioning and restoration liability	8	9	34	39
Letter of credit charges	-	-	-	8
Interest on lease liability	3	-	14	-
Interest on Credit Facility	272	294	1,232	1,034
	281	302	1,276	1,071

Interest on the Credit Facility had initially been based on US dollar LIBOR + 3% margin. The revised Credit Facility amendment dated November 2018 increased the margin to 3.75% effective January 1, 2019. An amendment to the Credit Facility dated November 2019 further increased the margin to 3.95% effective November 5, 2019. See details of the Credit Facility below.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended March 31 2020	2019	Twelve months ended March 31 2020	2019
Geological and geophysical	62	99	263	309
Drilling	1	1,530	146	2,360
Completions	21	844	1,365	1,677
Acquisition	(152)	-	261	-
	(68)	2,473	2,035	4,346
Exploration and evaluation expenditures	-	60	22	930
Development and production expenditures	(68)	2,413	2,013	3,416
	(68)	2,473	2,035	4,346

The development and production expenditure of $2.0 million for the full year fiscal 2020 represents to final capital requirements for the 2019 drilling campaign. The $0.2 million credit under acquisition represents net proceeds from the sale of our rig that had been in storage and written off.

CREDIT FACILITY

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

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

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

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was not in compliance with its debt service coverage ratio covenant at March 31, 2020. Subsequent to March 31, 2020, the Company received a waiver from its lender in respect of the March 31, 2020 covenant breach.

SHARE CAPITAL

Trading history	**Three months ended March 31**		**Twelve months ended March 31**	
	2020	**2019**	**2020**	**2019**
High ($)	0.10	0.14	0.13	0.18
Low ($)	0.05	0.10	0.05	0.09
Close ($)	0.08	0.12	0.08	0.12
Volume (000s)	1,418	2,178	3,179	9,778
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 25, 2020, there were 102,266,694 common shares issued and outstanding, together with 3,472,500 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, lease liability and the Credit Facility and amounted to $18.9 million at March 31, 2020 (March 31, 2019 - $19.1 million).

At March 31, 2020, the Company had a working capital deficiency of $14.4 million, including cash and short-term deposits of $1.0 million and restricted cash of $0.1 million, compared to a working capital deficiency of $12.7 million at March 31, 2019. The working capital deficiencies are primarily a result of the Credit Facility of $17.7 million maturing in October 2020. The Company has no available undrawn debt capacity under the Credit Facility. The Company was not in compliance with its debt service coverage ratio covenant at March 31, 2020. The Company's current forecast indicates that it will not be in compliance with its DSCR covenant over the next twelve months. Subsequent to March 31, 2020, the Company received a waiver from its lender in respect of the March 31, 2020 covenant breach.

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

At year ended March 31, 2020, the Company has its US$12.4 million Credit Facility maturing at the end of October 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 oil 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.

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

(US$000s)	
Credit Facility	
Fiscal year 2021	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.

COMMITMENTS

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

At March 31, 2020, the Company had the following capital work commitments:

Country and permit	**Work program**	**Obligation period ending**	**Estimated expenditure (net) (millions CAD$) (1)**
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2021	12.3(2)
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2020 at an exchange rate of AUS$1.00 = CAD$0.8700.

(2) Subsequent to year end, the Company received confirmation that the commitment on ATP 934 was reduced to $1.2 million. In exchange for the reduction in commitment Bengal will relinquish 50% of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021.

At March 31, 2020, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2020 to November 2023	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	582	155	315	112	-
Decommissioning and restoration	3,690	-	642	64	2,984
	4,272	155	957	176	2,984

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2020 **Q4 2020**	Dec 31 2019 Q3 2020	Sep 30 2019 Q2 2020	June 30 2019 Q1 2020	Mar 31 2019 Q4 2019	Dec 31 2018 Q3 2019	Sep 30 2018 Q2 2019	Jun 30 2018 Q1 2019
Oil sales	1,140	2,425	2,576	1,962	2,667	2,014	3,315	3,215
Cash flow from operations	27	259	527	316	635	434	603	1,019
Funds from (used in) operations(1)	(849)	599	724	(13)	842	(247)	750	875
Per share – basic and diluted ($)	(0.01)	0.01	0.01	0.00	0.01	(0.01)	0.00	0.01
Net income (loss)	(2,196)	556	(506)	(750)	(2,144)	883	(728)	(486)
Per share – basic and diluted ($)	(0.02)	0.01	(0.00)	(0.01)	(0.02)	0.01	(0.01)	(0.00)
Capital expenditures	(68)	346	477	1,280	2,473	298	1,274	301
Working capital (deficiency)	(14,434)	(13,823)	(14,120)	(13,964)	(12,740)	6,331	(3,353)	(2,915)
Total assets	39,572	41,391	40,849	40,373	42,489	44,291	43,547	44,867
Shares outstanding (000s)	102,267	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	254	280	333	249	281	300	292	318
Operating netback(1) ($/bbl)	10.77	59.68	53.78	49.01	76.82	22.54	59.58	55.69

(1) See “Non-IFRS Measurements” on page 20 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 Q4 fiscal 2020 due to COVID-19 resulted in the lowest sales revenue in the past eight quarters. With the deferment of capital expenditures at least until 2021, depressed revenue and cash flow are expected through 2021.

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, 2020 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 has limited 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.

(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– *Standards of Disclosure For Oil and Gas Activities ("NI-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

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. The current challenging economic climate may lead to adverse changes in cash flow or working capital levels, which may also have a direct impact on the Company's results and financial positions. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

NEW ACCOUNTING STANDARDS

Leases

Effective April 1, 2019, the Company adopted IFRS 16 Leases ("IFRS 16"), which replaces previous IFRS guidance on leases: IAS 17 Leases ("IAS 17"). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in net income (loss) and comprehensive income (loss) in the consolidated statements of comprehensive income (loss). IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 9), with a corresponding increase to lease liability (Note 13). There was an adjustment of $ 31,232 to the right-of-use assets for lease incentives previously received.

Business combinations

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

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

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 (used in) operations, funds from (used in) operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Operating netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Operating netback per barrel equals netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from (used in) 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 (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) 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 (used in) operations, which is used in this MD&A:

($000s)	Three months ended March 31 2020	2019	Twelve months ended March 31 2020	2019
Cash from operating activities	27	635	1,129	2,691
Changes in non-cash working capital	(876)	207	(668)	(471)
Funds (used in) from operations	(849)	842	461	2,220

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 2020	2019	Twelve months ended March 31 2020	2019
Net loss	(2,196)	(2,144)	(2,896)	(2,475)
Unrealized loss (gain) on financial instruments	(1,760)	740	(1,290)	(1,086)
Unrealized foreign exchange (gain) loss	2,219	(104)	2,415	1,295
Non-cash impairment of non-current assets	626	1,906	646	2,791
Adjusted net income (loss)	(1,111)	397	(1,125)	525

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.

Risks Relating to the COVID-19 Pandemic

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally, resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The Company is exposed to the risks relating to public health emergencies, including COVID-19, and related government responses which may have a material and adverse effect on the Company's business, financial condition and operations. The extent to which COVID-19 may impact the Company's business is uncertain and not currently determinable. In the event that the prevalence of COVID-19 continues to increase, governments may enact further measures or extend existing measures impacting the Company's operations, suppliers, customers, counterparties, shippers, partners, employee health, the availability and function of regulatory agencies, or the flow of labour. The Company continues to monitor and is taking precautions to adhere to all applicable occupational health guidelines and all recommendations from applicable government agencies and public health authorities. Such measures and mandates may also increase the Company's expenses.

The duration and continued severity of the COVID-19 pandemic is uncertain, and may continue for a significant period of time.

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. Global oil prices have recently been negatively impacted by oversupply and demand destruction associated with the COVID-19 pandemic. 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, may 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 may 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 may affect Bengal's ability to expend the necessary capital to replace its reserves or to maintain its production. If Bengal's funds from (used in) 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;*
- *Pipeline oil volume, sales and price estimates;*
- *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 expected timing of restarting the 2020 multi-well development and appraisal drilling campaign;*
- *The expected timing of the pilot reservoir maintenance scheme at the Cuisinier 24 well and the anticipated production increases resulting from the injection of produced formation water and future water flood expansion phases;*
- *The planned extended production tests on the Nubba gas discovery well and expected timing of tying in the well*
- *The expectation of placing the appropriate hedges on the Company's production;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of in the Cuisinier field;*
- *The timing of he extended production test on the Nubba gas discovery well on the Wompi block;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *The possibility and timing of a third party farm in agreement 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;*
- *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;*
- *Anticipated adverse impacts on the Company's operating results, liquidity and financial position as a result of the current economic climate, and the expected persistence of depressed revenue and cash flow through 2021;*
- *Expectations that a firm agreement will be executed with a third party with an interest in farming-in on a portion of the ATP 934 block;*
- *The anticipated commercial viability of certain areas of the Barta block;*
- *The Company's plans to target future foreign operations in jurisdictions with known long-term oil and gas ventures; and*
- *The continued integration of subsurface data to select drilling locations.*

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;*
- *Uncertainties associated with the COVID-19 pandemic;*
- *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, 2020 (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 discloses unbooked drilling locations. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Internal Estimates

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

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

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

STOCK EXCHANGE LISTING – TSX: BNG

Bengal
ENERGY LTD.

Consolidated Financial Statements

Years Ended
March 31, 2020 and 2019

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, 2020. 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, 2020 and March 31, 2019
- 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, 2020 and March 31, 2019, 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.

Material Uncertainty Related to Going Concern

We draw your attention to note 2 in the financial statements, which indicates that the Company has no available undrawn debt capacity under its credit facility which will expire on October 31, 2020. As at March 31, 2020, the Company was not in compliance with a debt covenant and therefore the debt is due on demand. The Company's current forecast also indicates that it will not be in compliance with its covenant over the next twelve months. The Company's ability to continue as a going concern is dependent upon the ability to generate positive cash flow from operating activities and to renew the current credit facility or to raise additional financing to meet its future development costs associated with the petroleum and natural gas assets and to continue with other capital projects and operations.

As stated in note 2 in the financial statements, these events or conditions, along with other matters as set forth in note 2 in the financial statements, indicate that a material uncertainty exists that may cast significant doubt on the Company's ability to continue as a going concern.

Our opinion is not modified in respect of this matter.

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 24, 2020

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31	Notes	2020	2019
Assets			
Current assets:			
Cash and cash equivalents	6	$ 998	$ 2,891
Restricted cash		140	140
Trade and other receivables	7	1,639	2,972
Prepaid expenses and deposits		126	136
Fair value of financial instruments	21	1,447	177
		4,350	6,316
Exploration and evaluation assets	8	8,930	9,711
Property, plant and equipment	9	26,292	26,462
Total assets		$ 39,572	$ 42,489
Liabilities and Shareholders' Equity			
Current liabilities:			
Trade and other payables	10	$ 1,041	$ 2,574
Current portion of credit facility	12	17,695	16,482
Current portion of lease liability	13	48	-
		18,784	19,056
Decommissioning and restoration liability	14	3,690	1,977
Lease liability	13	156	-
		22,630	21,033
Shareholders' equity:			
Share capital	15	98,100	98,100
Contributed surplus		7,861	7,832
Accumulated other comprehensive loss		(1,651)	(4)
Deficit		(87,368)	(84,472)
		16,942	21,456
Total liabilities and shareholders' equity		$ 39,572	$ 42,489

Going concern (Note 2)

Commitments (Note 24)

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	2020	2019
Revenue			
Oil sales	17	$ 8,103	$ 11,211
Royalties		(316)	(570)
		7,787	10,641
Realized gain (loss) on financial Instruments	21	533	(1,236)
Unrealized gain on financial instruments	21	1,290	1,086
		9,610	10,491
Expenses			
General and administrative		3,303	2,900
Operating		3,773	3,625
Depletion and depreciation	9	1,397	1,457
Impairment	8,9	646	2,791
Share-based compensation		28	69
Foreign exchange loss		2,304	1,053
		11,451	11,895
Other (income) expense			
Other		(221)	-
Finance expense	20	1,276	1,071
Net loss		(2,896)	(2,475)
Exchange differences on translation of foreign operations		(1,647)	(1,038)
Comprehensive loss		$ (4,543)	$ (3,513)
Loss per share - basic & diluted	18	$ (0.03)	$ (0.02)
Weighted average shares outstanding (000s) – basic and diluted	18	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	2020	2019
Share capital		
Balance at beginning and end of year	$ 98,100	$ 98,100
Contributed surplus		
Balance at beginning of year	7,832	7,755
Share-based compensation – expensed	28	69
Share-based compensation – capitalized	1	8
Balance at end of year	7,861	7,832
Accumulated other comprehensive income (loss)		
Balance at beginning of year	(4)	1,034
Exchange differences translation of foreign operations	(1,647)	(1,038)
Balance at end of year	(1,651)	(4)
Deficit		
Balance at beginning of year	(84,472)	(81,997)
Net loss	(2,896)	(2,475)
Balance at end of year	(87,368)	(84,472)
Total shareholders' equity	$ 16,942	$ 21,456

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	2020	2019
Operating activities:			
Net loss for the year		$ (2,896)	$ (2,475)
Add (deduct) non-cash items			
Depletion and depreciation		1,397	1,457
Accretion on decommissioning and restoration liability		34	39
Accretion on credit facility		301	129
Gain on asset sale		(221)	-
Share-based compensation		28	69
Interest on lease liability		14	-
Lease incentive		31	-
Impairment		646	2,791
Unrealized gain on financial instruments		(1,290)	(1,086)
Unrealized foreign exchange loss		2,415	1,296
Funds from operations		459	2,220
Change in non-cash working capital	23	668	471
Net cash from operating activities		1,127	2,691
Investing activities:			
Exploration and evaluation expenditures	8	(22)	(930)
Petroleum and natural gas property expenditures	9	(2,013)	(3,416)
Proceeds on asset sale		221	-
Change in non-cash working capital	23	(947)	1,161
Net cash used in investing activities		(2,761)	(3,185)
Financing activities:			
Repayment of credit facility	12	-	(176)
Facility extension fees	12	(98)	(132)
Lease payments	13	(60)	-
Change in non-cash working capital	23	(2)	(28)
Net cash used in financing activities		(160)	(336)
Net decrease in cash and cash equivalents		(1,794)	(830)
Cash and cash equivalents, beginning of year		2,891	3,904
Impact of foreign exchange on cash and cash equivalents		(99)	(183)
Cash and cash equivalents, end of year		$ 998	$ 2,891

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, 2020 and 2019 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.

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

2. BASIS OF PREPARATION AND GOING CONCERN

These financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). See note 3 for significant accounting policies.

The financial statements were approved and authorized for issuance by the Board of Directors on June 25, 2020.

These financial statements have been prepared on a historical cost basis, except for commodity contracts as discussed in Note 21.

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

Going concern

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

As at March 31, 2020, the Company had a working capital deficiency of $14.4 million and recognized a net loss of $2.9 million for the year ended March 31, 2020. The Company has no available undrawn debt capacity under its credit facility which will expire on October 31, 2020. As at March 31, 2020, the Company was not in compliance with its debt service coverage ratio (“DSCR”) (refer to Note 12) and therefore the debt is due on demand. The Company’s current forecast indicates that it will not be in compliance with its DSCR covenant over the next twelve months. Subsequent to March 31, 2020, the Company has received a waiver in respect of the March 31, 2020 covenant breach. The Company also has significant capital work commitments associated with its exploration and evaluation assets.

The Company’s ability to continue as a going concern is dependent upon the ability to generate positive cash flow from operating activities and to renew the current credit facility or to raise additional financing to meet its future development costs associated with petroleum and natural gas assets and to continue with other capital projects and operations. There can be no assurances that the facility will be renewed or additional sources of funding will be available for the Company. These matters cause material uncertainty which may cast significant doubt on the Company’s ability to continue as a going concern.

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

3. 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

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

Financial instruments comprise of cash and cash equivalents, restricted cash, trade and other receivables, derivative contracts, trade and other payables and credit facility.

i. Classification and measurement of financial assets:

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss (“FVTPL”):

- it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income (“FVOCI”) if it meets both of the following conditions and is not designated at FVTPL:

- it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

On initial recognition of an equity investment that is not held for trading, the Partnership may irrevocably elect to present subsequent changes in the investment’s fair value in other comprehensive income (“OCI”). This election is made on an investment-by-investment basis.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI as measured as FVTLP if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

A financial asset (unless it is a trade receivable without a significant financing component that is initially measured at the transaction price) is initially measured at fair value plus, for an item not at FVTPL, transaction costs that are directly attributable to its acquisition.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets at amortized cost

These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

c) Debt investments at FVOCI

These assets are subsequently measured at fair value. Interest income calculated using the effective interest method, foreign exchange gains and losses and impairment are recognized in profit or loss. Other net gains and losses are recognized in OCI. On derecognition, gains and losses accumulated in OCI are reclassified to profit or loss.

ii. Classification and measurement of financial liabilities:

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified cash and cash equivalents, restricted cash, trade and other receivables, and trade and other payables as ‘amortized cost’.

iii. **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 Fair Value Through Profit and Loss (“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.

iv. 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 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

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 ("COSP 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 COSP Agreement once the product is shipped to the end customer and lifted.

(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, lease liability

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) Leases

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

Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions. Prior to the adoption of IFRS, the Company only had operating leases that were recognized over the lease term.

4. NEW ACCOUNTING STANDARDS

Business combinations

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

Leases

Effective April 1, 2019, the Company adopted IFRS 16 Leases (“IFRS 16”), which replaces previous IFRS guidance on leases: IAS 17 Leases (“IAS 17”). Under IAS 17, lessees were required to determine if the lease was a finance or operating lease, based on specified criteria of whether the lease transferred significantly all the risks and rewards associated with ownership of the underlying asset. Finance leases were recognized on the consolidated statement of financial position while operating leases were recognized in profit or loss in the consolidated statements of loss and comprehensive loss. IFRS 16 introduced a single lease accounting model for lessees which requires a right-of-use asset and liability to be recognized on the statement of financial position for contracts that are, or contain, a lease. The Company adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $249,933 increase to right-of-use assets (Note 9), with a corresponding increase to lease liability (Note 13). There was an adjustment of $ 31,232 to the right-of-use assets for lease incentives previously received.

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

5. MANAGEMENT JUDGMENTS AND 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.

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. In addition, global commodity prices have declined significantly due to disputes between major oil producing countries combined with the negative impact to oil demand from the COVID-19 pandemic. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The current challenging economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgements made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

(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.

(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

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. The current challenging economic climate may lead to adverse changes in cash flow or working capital levels, which may also have a direct impact on the Company's results and financial positions. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

6. CASH AND CASH EQUIVALENTS

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, 2020**	**March 31, 2019**
Cash and bank balances	994	2,885
Short-term deposits	4	6
	998	2,891

7. 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, 2020**	**March 31, 2019**
Due from joint venture partners	1,628	2,928
Other receivables	11	44
	1,639	2,972

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

($000s)	
Balance, April 1, 2018	10,102
Additions	930
Acquisition	-
Capitalized share-based compensation	4
Impairment	(894)
Exchange adjustments	(431)
Balance, March 31, 2019	9,711
Additions	22
Impairment	(10)
Exchange adjustments	(793)
Balance, March 31, 2020	8,930

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

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

($000s)	
ATP 732P – Tookoonooka	4,743
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)	2,437
ATP 934 – Barrolka	1,750
Balance, March 31, 2020	8,930

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.

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.

9. PROPERTY, PLANT AND EQUIPMENT (“PP&E”)

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, April 1, 2018	44,236	344	-	44,580
Additions	3,416	-	-	3,416
Capitalized share-based compensation	4	-	-	4
Change in decommissioning and restoration liability	448	-	-	448
Exchange adjustments	(2,737)	-	-	(2,737)
Balance, March 31, 2019	45,367	344	-	45,711
Additions	1,752	-	-	1,752
Acquisition	1,798	-	-	1,798
Adoption of IFRS 16	-	-	219	219
Capitalized share-based compensation	1	-	-	1
Change in decommissioning and restoration liability	368	-	-	368
Exchange adjustments	(5,464)	-	-	(5,464)
Balance, March 31, 2020	43,822	344	219	44,385

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment losses:				
Balance, April 1, 2018	17,172	301	-	17,473
Depletion and depreciation	1,446	11	-	1,457
Impairment	1,897	-	-	1,897
Exchange adjustments	(1,578)	-	-	(1,578)
Balance, March 31, 2019	18,937	312	-	19,249
Depletion and depreciation	1,343	7	47	1,397
Impairment	636	-	-	636
Exchange adjustments	(3,189)	-	-	(3,189)
Balance, March 31, 2020	17,727	319	47	18,093

($000s)				
Net carrying amount:				
At March 31, 2019	26,430	32	-	26,462
At March 31, 2020	26,095	25	172	26,292

During fiscal 2020, the Company acquired four Petroleum Leases ("PLs"), for nominal cash consideration. The associated decommissioning and restoration liability is valued at $1.54 million and acquisition costs of $0.26 million. All four PLs are located adjacent to the Company's existing gas exploration block ATP 934 in the Cooper Basin.

During fiscal 2020, the Company capitalized $0.3 million of general and administrative expense (2019 - $0.4 million.

The calculation of depletion for the year ended March 31, 2020 included $59.7 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2019 - $60.9 million).

The Company recorded an impairment charge of $1.9 million and $0.6 million during fiscal 2019 and fiscal 2020, respectively, due to uneconomic drilling results.

At March 31, 2020, the Company evaluated its petroleum and natural gas assets for indicators of impairment. Due to industry and market conditions, especially the decline in crude oil prices, the Company identified that impairment triggers were present at March 31, 2020. The Company performed an impairment test but no adjustment was required. The impairment test compared the carrying amount of the Cuisinier CGU to the fair value less costs of disposal (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, discounted at 10% to 30% depending on the various categories of reserves. Notwithstanding there was no additional impairment recognized, other than with respect to the Cuisinier 27 well, there is a reasonable possibility that the determination of a recoverable amount could result in an impairment in future periods if commodity prices and/or discount rates applied to various categories of reserves are adversely impacted by market conditions.

The following forecast commodity prices were used at March 31, 2020:

Year	Exchange Rate USD/CAD	Brent Blend Crude Oil FOB North Sea Then Current USD/bbl
2020	0.727	38.64
2021	0.730	45.50
2022	0.735	52.50
2023	0.740	57.50
2024	0.745	62.50
2025	0.750	62.95
2026	0.750	64.13
2027	0.750	65.33
2028	0.750	66.56
2029	0.750	67.81
2030+	0.750	+2.0%/yr.

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

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, discounted at a pre-tax rate of 20%. Management recognizes that all assumptions and estimates affecting the value are subject to a high degree of uncertainty. No further impairment was recorded.

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

Year	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.

10. TRADE AND OTHER PAYABLES

($000s)	March 31, 2020	March 31, 2019
Trade payables	417	1,525
Accrued liabilities and other payables	624	1,049
	1,041	2,574

11. 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	2020	2019
Loss before taxes	(2,896)	(2,475)
Statutory tax rate	26%	27%
Expected income tax recovery	(753)	(668)
Change in enacted tax rates	2,054	-
Share-based compensation	7	19
Effect of tax rate in foreign jurisdiction	(66)	476
Other	131	(54)
Changes in unrecognized tax asset	(1373)	227
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	2020	2019
Non-capital losses	47,287	50,833
Net capital losses	5,092	5,992
P&NG properties	7,478	8,901
Share issue costs	-	211
Decommissioning obligations	-	-
	59,857	65,937

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

($000s)		
Year ended March 31	**2020**	**2019**
Property, plant and equipment	5,114	4,878
Fair value of financial instruments	434	53
Foreign exchange	(1,559)	(802)
Decommissioning obligations	(1,107)	(593)
Non-capital losses	(2,897)	(3,536)
	-	-

At March 31, 2020, the Company had approximately $31.8 million and $25.2 million of non-capital losses in Canada and Australia respectively (2019 - $26.9 million and $28.4 million, respectively), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026 to 2038. 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, 2020, the Company has no deferred tax liabilities in respect of these temporary differences.

On May 28, 2019, the Government of Alberta reduced the general corporate income tax rate to 8% (from 12%) over four years. Starting July 1, 2019, the general corporate tax rate decreased to 11% (from 12%), with further 1% rate reductions every year on January 1 until the general corporate tax rate is 8% on January 1, 2022, which results in a combined Canadian federal and provincial income tax rate of 23%.

12. CREDIT FACILITY

($000s)	
Gross proceeds	15,364
Total cash fees	(994)
Repayment	(2,160)
	12,210
Facility extension fees	(227)
Unrealized foreign exchange loss	3,264
Accretion	1,235
Balance, March 31, 2019	16,482
Unrealized foreign exchange loss	1,010
Facility extension fees	(98)
Accretion	301
Balance, March 31, 2020	17,695

($000s)

	March 31, 2020	March 31, 2019
Current portion	17,695	16,482
Non-current portion	-	-

The Company initially entered into a US $25 million reserves based revolving credit facility in October 2014, placing an initial draw of US $14 million. The facility is secured by and available to the Company's producing assets in the Cuisinier field in Australia's Cooper Basin. On August 26, 2016, the Company repaid US $1.5 million.

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

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

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

The Credit Facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the Credit Facility. The Company was not in compliance with the debt service coverage ratio covenant at March 31, 2020. The Company's current forecast indicates that it will not be in compliance with its DSCR covenant over the next twelve months (refer to note 2). Subsequent to March 31, 2020, the Company has received a waiver from its lender in respect of the March 31, 2020 covenant breach.

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

(US$000s)	
Fiscal year 2021	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 21(b)).

13. LEASE LIABILITY

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

($000s)	
Balance, March 31, 2019	-
IFRS 16 transition adjustment (Note 3)	250
Interest	14
Payments	(60)
Balance, March 31, 2020	204
Current portion of lease liability	(48)
Non-current portion of lease liability	156

14. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)	
Balance, April 1, 2018	1,556
Change in estimate	168
Additions	280
Accretion	39
Exchange adjustments	(66)
Balance, March 31, 2019	1,977
Change in estimate	368
Acquisition (Note 9)	1,538
Accretion	34
Exchange adjustments	(227)
Balance, March 31, 2020	3,690

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, 2020 is approximately $4.0 million (March 31, 2019 – $2.5 million) which will be incurred between 2023 and 2054. An inflation factor of 1.73% (March 31, 2019 – 1.78%) and a risk-free discount rate of 0.77% (March 31, 2019 – 1.79%) have been applied to the decommissioning liability at March 31, 2020.

15. 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 at March 31, 2019 and 2020	102,266,694	98,100

16. SHARE-BASED COMPENSATION

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

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

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

A summary of stock option activity is presented below:

	Options	**Weighted average exercise price**
		$
Balance, March 31, 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
Expired	(152,201)	0.11
Forfeited	(477,799)	0.12
Balance, March 31, 2020	3,472,500	0.12
Exercisable, March 31, 2020	1,902,904	0.11

		Options Outstanding	Options Exercisable
Exercise Price	**Number Outstanding**	**Remaining Life (years)**	**Number Exercisable**
$0.10	2,410,000	2.25	1,606,674
$0.11	250,000	3.00	83,334
$0.125	25,000	2.50	16,667
$0.18	787,500	0.33	196,229
	3,472,500	1.87	1,902,904

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

Assumptions:	
Risk-free interest rate (%)	2.00
Expected life (years)	5
Expected volatility (%)(1)	95
Estimated forfeiture rate (%)	20
Weighted average fair value of options granted	$0.08
Weighted average share price on date of grant	$0.11

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

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

17. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Crude Oil Sales and Purchase Agreement ("COSP 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 COSP Agreement once the product is shipped to the end customer and lifted.

The transaction price as prescribed in the COSP 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 COSP 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.

18. 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	**2020**	**2019**
Net loss for the year	(2,896)	(2,475)
Weighted average number of		
common shares – basic and diluted (000s)	102,267	102,267
Basic and diluted loss per share	$ (0.03)	$ (0.02)

For the year ended March 31, 2020, there were 3,472,500 (March 31, 2019 - 4,102,500) options considered anti-dilutive.

19. 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	**2020**	**2019**
Salaries and employee benefits	838	982
Share-based compensation(1)	26	69
	864	1,051

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

20. FINANCE EXPENSE

($000s)		
Year ended March 31	**2020**	**2019**
Interest income	(4)	(10)
Accretion on decommissioning		
and restoration liability	34	39
Letter of credit charges	-	8
Interest on lease liability	14	-
Interest on Credit Facility	1,232	1,034
	1,276	1,071

21. 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, 2020, Bengal's receivables consisted of $1.63 million (March 31, 2019 - $2.93 million) from joint venture partners (of which $0.69 million has been collected subsequent to year end) and $0.01 million (March 31, 2019 - $0.04 million) of other receivables.

Bengal has a COSP 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, 2020 (March 31, 2019 - $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, 2020 and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the year ended March 31, 2020 (March 31, 2019 – $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, lease liability and Credit Facility and amounted to $18.9 million at March 31, 2020 (March 31, 2019 - $19.1 million).

At March 31, 2020, the Company had a working capital deficiency of $14.4 million, including cash and short-term deposits of $1.0 million and restricted cash of $0.1 million, compared to a working capital deficiency of $12.7 million at March 31, 2019. The working capital deficiencies are primarily a result of the Credit Facility of $17.7 million maturing in October 2020. The Company has no available undrawn debt capacity under the Credit Facility.

At March 31, 2020, the Company has significant capital spending commitments to be incurred by February 2021 on ATP 934P of $12.3 million and has its US$12.4 million Credit Facility that matures in October 2020. Subsequent to year end, the Company received confirmation that the commitment on ATP 934 was reduced to $1.2 million. In exchange for the reduction in commitment the Company will relinquish 50% of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. As at March 31, 2020, the Company was not in compliance with its debt service coverage ratio ("DSCR") (refer to Note 12). The Company's current forecast indicates that it will not be in compliance with its DSCR covenant over the next twelve months (refer to Note 2). Subsequent to March 31, 2020, the Company has received a waiver from its lender in respect of the March 31, 2020 covenant breach.

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. See going concern considerations in note 2.

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.

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

(US$000s)	
Credit Facility	
Fiscal year 2021	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 at March 31, 2020:

($000s)	CAD$	AUS$	US$	Total
Cash and cash equivalents	427	22	549	998
Restricted cash	140	-	-	140
Trade and other receivables	10	211	1,418	1,639
Fair value of financial instruments	-	-	1,447	1,447
Trade and other payables	(202)	(834)	(5)	(1,041)
Credit Facility	-	-	(17,695)	(17,695)
Lease liability	(204)	-	-	(204)
	171	(601)	(14,286)	(14,716)

Exchange rates as at March 31:	2020	2019
Number of CAD$ for 1 AUS$	0.87	0.95
Number of CAD$ for 1 US$	1.42	1.33

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, 2020, 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, 2020 – April 30, 2020	Oil - swap	5,000	59.49	59.49

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	233	-	233
Non-current fair value of financial instruments	-	-	-
	233	-	233

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	209	-	209
Non-current fair value of financial instruments	-	-	-
	209	-	209

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	188	-	188
Non-current fair value of financial instruments	-	-	-
	188	-	188

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	157	-	157
Non-current fair value of financial instruments	-	-	-
	157	-	157

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	146	-	146
Non-current fair value of financial instruments	-	-	-
	146	-	146

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	139	-	139
Non-current fair value of financial instruments	-	-	-
	139	-	139

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	130	-	130
Non-current fair value of financial instruments	-	-	-
	130	-	130

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	125	-	125
Non-current fair value of financial instruments	-	-	-
	125	-	125

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

($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	120	-	120
Non-current fair value of financial instruments	-	-	-
	120	-	120

Total ($000s)	Oil – swap	Oil – put	Total
Current fair value of financial instruments	1,447	-	1,447
Non-current fair value of financial instruments	-	-	-
	1,447	-	1,447

A US$1.00 increase in the future crude oil price per barrel would result in an approximate US$42,600 (CAD$60,400) decrease in the fair value of financial instruments at March 31, 2020, while a US $1.00 decrease would result in an increase of approximately US$42,600 (CAD$60,400) 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, 2020 as the funds are not invested in interest-bearing instruments. The Credit Facility carries a floating interest rate based on quoted US dollar LIBOR rates. The Company had no interest rate derivatives at March 31, 2020.

For the year ended March 31, 2020, a 1% increase in US LIBOR would increase interest expense by $164,000.

22. 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.

23. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s) Year ended March 31	2020	2019
Trade and other receivables	1,333	1,335
Prepaid expenses and deposits	10	18
Trade and other payables	(1,533)	342
Effect of change in foreign exchange rates	(91)	(91)
	(281)	1,604

Attributable to:

Operating	668	471
Investing	(947)	1,161
Financing	(2)	(28)
	(281)	1,604

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

Cash interest paid and received **($000s)** **Year ended March 31**	**2020**	**2019**
Cash interest paid	1,020	730
Cash interest received	4	10

24. COMMITMENTS

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

At March 31, 2020, the Company had the following capital work commitments:

Country and permit	**Work program**	**Obligation period ending**	**Estimated expenditure (net) (millions CAD$)** [(1)]
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2021	12.3[(2)]
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2020 at an exchange rate of AUS$1.00 = CAD$0.8700.

(2) Subsequent to year end, the Company received confirmation that the commitment on ATP 934 was reduced to $1.2 million. In exchange for the reduction in commitment Bengal will relinquish 50% of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021.

At March 31, 2020, the contractual obligations for which the Company is responsible are as follows:

($000s) **Contractual obligations** **April 2020 to March 2025**	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Office lease	582	155	315	112	-
Decommissioning and restoration	3,690	-	642	64	2,984
	4,272	155	957	176	2,984

25. SEGMENTED INFORMATION

As at March 31, 2020, 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, 2020**	**Australia**	**Corporate**	**Total**
Revenue	8,103	-	8,103
Interest revenue	3	1	4
Interest expense	1,232	14	1,246
Depletion and depreciation	1,343	54	1,397
Impairment	646	-	646
Net loss	(1,651)	(1,245)	(2,896)
Exploration and evaluation expenditures	22	-	22
Petroleum and natural gas property expenditures	2,013	-	2,013
($000s)			
As at March 31, 2020			
Exploration and evaluation assets	8,930	-	8,930
Petroleum and natural gas properties	26,095	-	26,095
Total Assets	38,770	802	39,572
Total Liabilities	22,224	406	22,630

($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) **As at March 31, 2019**			
Exploration and evaluation assets	9,711	-	9,711
Petroleum and natural gas properties	26,430	-	26,430
Total Assets	42,187	302	42,489
Total Liabilities	20,793	240	21,033

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

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

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