Bengal
ENERGY LTD.

International Exploration & Production

2018 Annual Report

Twelve Months Ended

March 31, 2018

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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

During fiscal 2018, Bengal Energy Ltd. ("Bengal" or the "Company") has been active across numerous fronts. This included focused geological and geophysical efforts to accelerate the drilling of an exciting westward extension to the productive Cuisinier field, a thorough geophysical re-work of seismic data on ATP 934 resulting in what we believe to be a paradigm shift in exploration risk reduction, and negotiating an amendment to Bengal's credit facility. In addition, the Company was active in identifying and analyzing production acquisition opportunities within our core areas in onshore Australia. All these activities have positioned the Company well, setting the stage for future years' exploration and development drilling programs in a time of improved commodity pricing.

At Cuisinier, the Company was successful in negotiating lower transportation costs for its oil sales, and continued premium pricing was achieved through the new Crude Oil Sale and Purchase Agreement entered into at the end of fiscal Q1 2018.

Bengal will continue to maintain a prudent approach to fiscal 2019 activities, but look forward to the results of the high-impact Chookola well which was identified on the Barta West 3D seismic program in the Barta block on ATP 752. This exploration well, targeting three separate geological horizons, is scheduled to be drilled in August of 2018. We are also working diligently with our joint venture partners to advance a waterflood pilot at Cuisinier, hydraulically stimulate select producing wells, as well as identify 9 to 10 development drilling locations for 2019 and 2020.

Production for fiscal year ended March 31, 2018 averaged 360 bopd, a decrease of only 5% over fiscal 2017 which speaks to the efficiency of the operator in effectively managing the reservoir during a time of no in-field drilling. This modest decrease is due to natural production declines. Bengal saw a decline of 9% in its Proved Plus Probable ("2P") reserves during the fiscal year ended March 31, 2018 to 6,416 Mbbls from the previous year and Proved reserves decreased by 6% to 2,583 Mbbls. On the other hand, the net present value (NPV10, before tax) of Bengal's 2P reserves increased to $141 million, or $1.38 per share. The Company's 2P net asset value before tax, which deducts net debt from the net present value (NPV10, before tax), is $128.8 million or $1.26 per share. The 2P after tax, net asset value is $94.2 million and $0.92 per share. These increases in value are primarily a result of higher forecast crude oil prices. We remain confident in our ability to further grow the size and value of our reserves base through future drilling programs.

On ATP 934, a portion of the 2D data set has been processed and interpreted using an AVO/Inversion workflow which has led to a breakthrough in the Company's ability to more accurately predict presence of reservoir sandstones within coal rich sedimentary sequences which is not possible using conventional amplitude interpretation. Bengal believes this process will help de-risk drilling locations in future programs and is encouraged by recent natural gas discoveries surrounding the permit, which suggest the presence of a broader stratigraphically trapped gas resource in the region. ATP 934 is surrounded by producing gas fields, and infrastructure is developed with numerous gas pipelines crossing the Bengal permit providing market access.

We were successful in our goal of consolidating ownership in ATP 934 and acquired the 28.57% held by the remaining party with an effective date of August 1, 2017. With 100% interest, Bengal has commenced discussions with third parties who may have an interest in farming in on this block.

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

Bengal also successfully negotiated an amendment to its secured credit facility (the "Credit Facility") with the Australian-based Westpac Institutional Bank, which includes a deferment of principal payments on the

Credit Facility. The Credit Facility continues to have an expiry date of December 31, 2019 and provides a borrowing base of US$ 12.5 million, of which the full amount is currently drawn.

Considerable attention has been paid to maintaining balance sheet strength and optionality and to this end we thank our new CFO, Mr. Matthew Moorman, for his contributions and fiscal prudency in the face of commodity price volatility.

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 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, 2018 and 2017.

International exploration & production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2018 and 2017

FISCAL 2018 HIGHLIGHTS

Financial Highlights:

- **Summary of Reserves and Values**

  Reserve valuation increased year-over-year with total proved (1P) reserves at March 31, 2018 up by 37% to $62.9 million from March 31, 2017. Proved plus probable (2P) reserves increased in value by 19.5% to $141 million from 2017. Reserve values increased due to higher assumed oil prices combined with expected lower capital costs while reserve volumes declined due to lower expected capital spending.

- **Revenue**

  Crude oil sales for the fourth quarter of fiscal 2018 were $2.8 million, a 28% increase over the same quarter in the fiscal year 2017. Annual crude oil sales for fiscal 2018 were $10.7 million, a 15% increase over annual 2017. Both increases were due to a 31% improvement in US Brent pricing year-over-year.

- **Hedging**

  For the period April 2018 through December 2018, the Company has 65,261 barrels hedged using both puts and swaps at US$ 47/bbl. In addition the Company has hedged 15,906 barrels for the period January 2019 to March 2019 using both puts and swaps at US$ 55.70/bbl. This hedging program is required under the Company's Credit Facility.

- **Funds Flow from Operations**

  Funds flow from operations generated $0.5 million in fiscal Q4 2018 compared to $1.6 million in fiscal Q4 2017. The funds flow from operations for the full year 2018 was $3.7 million compared to $6.2 million for full year 2017. The primary reason for the reduced funds flow performance in both the 2018 fiscal Q4 and annual results was the drop in realized hedging value year-over-year. The fiscal year 2017 enjoyed $80/bbl hedges compared to $47/bbl hedges in the fiscal year 2018.

- **Earnings**

  The Company recorded a net loss for the fiscal Q4 2018 of $12.5 million compared to a net income of $1.9 million for the fiscal Q4 2017. For the full year 2018, the Company recorded a net loss of $12.3 million compared to a full year 2017 net loss of $2.8 million. In fiscal Q4 2018, the Company has taken a non-cash $12.2 million impairment primarily as related to ATP 732. After adjusting for unrealized gains and losses on financial instruments and foreign exchange, and the non-cash impairment of non-current assets, the adjusted earnings are $(143) and $1, 459 for the three and twelve months ended March 31, 2018, respectively.

Operational Highlights:

- **Production Volumes**

  Production (net to Bengal) in fiscal Q4 2018 averaged 334 barrels per day for a total production of 30,050 barrels compared to 344 average barrels per day in fiscal Q4 2017 or a total of 30,951 barrels, representing a reduction of 3%. For the full year 2018, production averaged 360 barrels per day compared to 379 barrels per day in 2017 for a reduction of 5%. Full year 2018 production was 131,455 barrels compared to 138,360 barrels in 2017. Normal production declines and reduced capital spending are the reason for the reduction in production for both the 2018 Q4 and full year.

- **Credit Facility Update**

  During fiscal 2018, the Company's credit facility with Westpac Banking Corporation was amended on September 25, 2017 and March 5, 2018 resulting in the elimination of the June 2018 principle repayment.

Bengal's producing assets are located in Australia's Cooper Basin, a region featuring many large oil and gas pools. The Company's core Australian assets: Barrolka, Cuisinier and Tookoonooka are situated within the southwest Queensland area of the Cooper Basin. Still in early stages, in terms of appraisal and development, Bengal believes these assets offer attractive upside potential. Australia features a stable political, fiscal and economic environment in which to operate, with a favourable royalty regime for oil and gas production.

OUTLOOK

AUSTRALIA

ATP 752 Barta Block Cuisinier

During the fourth quarter of fiscal 2018 the Company finalized the four wells at Cuisinier to be fracture stimulated. The frac programs are expected to be conducted early in the third calendar quarter with results known shortly thereafter. Prior frac programs showed positive results and increased well productivity.

The Barta West 3D seismic program processing has been completed and is in final stages of interpretation. The first exploration well location has been chosen (named Chookola #1) which is expected to spud mid third calendar quarter of 2018. It will take approximately 14 days to drill to evaluate all zones to the base of the Triassic with primary targets of the Murta, Birkhead and Doonmulla formations. All of these zones have been proven productive in the Cuisinier West area. Recent increases in crude oil pricing is steadily increasing corporate field oil netbacks which are now forecasted to exceed AUS $60 per barrel inclusive of the Company's hedging program and after any and all JV operational audit credits are accounted for.

The Barta joint venture has commenced planning for the implementation of a pressure maintenance/water injection pilot, which is designed to increase reservoir pressure and recovery factor for the offsetting Cuisinier wells. If results are encouraging, the implementation of a broader field wide program will be considered. Bengal's engineering evaluation suggests that Cuisinier is a favourable candidate for waterflood installation.

ATP 934 Barrolka

During the fourth quarter of fiscal 2018, Bengal completed consolidating the ownership of ATP 934 and now owns and controls a 100% working interest. Bengal has completed reprocessing of 500+ line kilometers of 2D seismic over the permit and interpretation of this data is now complete. Seismic amplitude inversion studies have highlighted several favourable areas of the permit allowing for additional work that may include the acquisition of 3D seismic in 2018. The Company is encouraged by the number of recent natural gas discoveries surrounding the Barrolka permit. This high success rate could indicate the presence of a broader stratigraphic trap and the presence of a more regional gas resource in the area. Bengal's strategy is to evaluate the potential of a broader resource while targeting more conventional prospects in the Permian Toolachee and Patchawarra sandstone reservoirs. Bengal is in preliminary discussions with third parties who may have an interest in farming in on this block.

ATP 732 Tookoonooka Block

The Tookoonooka Permit (ATP 732 – 100% WI effective January 28, 2016) is located in the emerging East Flank oil fairway of the Cooper Basin. A regulatory condition of an ATP granted under the Queensland Issuing Authority is the mandatory relinquishment of 8.33% of the original grant area per year. For ease of administration, the 8.33% per year is cumulative for four year periods therefore 33.33% is relinquished every fourth year. Post ATP issuance, on April 1, 2011 new legislation was put in place extending the first four year term by an additional two years thus requiring the first 33.3% relinquishment by March 31, 2017. The second four year term now ends March 31, 2019 at which time a further 33.3% of the original grant area is due to be relinquished. During fiscal 2017, the Company completed the required regulatory relinquishment of 1/3 of the block and filed a revised Later Work Program (LWP) application covering the period from March 2017 through March 2019 at which time a further 1/3 of the block will be relinquished. The aim with this relinquishment was to preserve all high-graded prospect areas thus far defined on acquired 2D and 3D seismic. Given this relinquishment program and the fact that, upon review the Company has no intention of developing or renewing such leases that are to be relinquished in March 2019, the carrying value of ATP 732 was written down to $5.38 million. The final LWP on the remaining 33.3% of the block will allow Bengal to further study the Permian gas potential along the northern flank of the permit identifying areas most favorable from a reservoir development and trap perspective. In addition, the southern part of the permit will be examined from an oil charge and migration perspective. While this southern area is close to the producing Jackson/Jackson South Field, which has produced greater than 49.4 million barrels of oil to date, the oil migration pathways and trapping configurations need further review. Upon completion of this work, the Company will engage with prospective third parties who may have an interest in farming in on this block.

ATP 752 Wompi

The Nubba-1 well encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas. Pressure testing, as well as logging, suggests that this Toolachee gas well could be part of a gas column that may be up to 70 metres in height. This implies that the prospective gas pay extends down dip of the Nubba well where seismic indicates the Toolachee section thickens. A Potential Commercial Area (the Yilgarn PCA), which will allow for commercialization, was granted on March 31, 2017. The produced natural gas would likely be pipeline connected to the nearest gas transmission line in the area, which is approximately 5 kilometres from the Nubba-1 well. Wompi (38% Bengal interest) offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential and the joint venture is currently evaluating the appropriate timing to continue the development of this discovery, which could occur during calendar 2019. The Yilgarn PCA was granted for an additional period of 15 years from March 31, 2017 and the associated work program is divided into three five-year terms. Work anticipated during these terms includes further geological, geophysical and engineering studies as well as extended production testing of the Nubba well and determination of commercial viability of the Nubba gas accumulation. The Company is reviewing the timing of this activity with the Joint Venture Operator.

AC/RL 10 (formerly AC/P 24), Ashmore Cartier Area, Timor Sea, Offshore Australia

Bengal holds a 10% working interest in the offshore Ashmore Cartier Retention License 10 ("**AC/RL 10**") located in the Ashmore Cartier area west of Australia comprised of approximately 168 km^2 (41,514 acres). Bengal is partnered with PTTEP Australia Timor Sea Pty Ltd. (90% working interest and operator).

This permit was granted as a five-year Petroleum Retention Lease, AC/RL 10 on March 22, 2013 which expired on March 21, 2018. A LWP application was successfully lodged and the permit has now been continued for a further five years. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options.

Business Development

The Company continues to examine potential transactions targeting complementary asset bases to increase reserves, production and cash flows per share.

OPERATING SUMMARY

$000s except per share, volumes and netback amounts	Three Months Ended March 31			Twelve Months Ended March 31		
	2018	2017	% Change	**2018**	2017	% Change
Oil sales revenue	**$2,783**	$2,179	28	**$10,710**	$ 9,294	15
Realized (loss) gain on financial instruments	**$(288)**	$971	(130)	**$568**	$ 4,712	(88)
Royalties	**$136**	$(347)	(139)	**$642**	$ (213)	(401)
% of revenue	**5**	(16)	(131)	**6**	(2)	(400)
Operating & transportation	**$1,077**	$987	9	**$3,718**	$ 4,864	(24)
Operating netback[1]	**$1,282**	$2,510	(49)	**$6,918**	$ 9,355	(26)
Cash from operations	**$858**	$643	33	**$3,627**	$ 4,515	(20)
Funds from operations:	**$525**	$1,639	(68)	**$3,737**	$ 6,196	(40)
Per share ($) (basic & diluted)[2]	**0.01**	0.02	(50)	**0.04**	0.08	(50)
Net income (loss)	**$(12,526)**	$1,931	(749)	**$(12,271)**	$ (2,768)	343
Per share ($) (basic & diluted)	**(0.12)**	0.02	(700)	**(0.12)**	(0.04)	200
Adjusted net income (loss)[3]	**(143)**	$1,181	(112)	**$1,459**	$ 3,605	(60)
Per share ($) (basic & diluted)	**0.00**	0.01	(100)	**0.01**	0.05	(80)
Capital expenditures	**939**	$681	38	**$3,511**	$ 5,618	(38)
Oil Production (bopd)	**334**	344	(3)	**360**	379	(5)
Netback[1] ($/boe)						
Revenue	**$ 92.61**	$ 70.40	32	**$81.47**	$ 67.17	21
Realized (loss) gain on financial instruments	**(9.58)**	31.37	(131)	**4.32**	34.06	(87)
Royalties	**4.53**	(11.21)	(140)	**4.88**	(1.54)	(417)
Operating & transportation	**35.84**	31.89	12	**28.28**	35.16	(20)
Netback/boe	**42.66**	$ 81.09	(47)	**$52.63**	$ 67.61	(22)

(1) Operating netback is a non-IFRS measure and includes realized losses on financial instruments. Netback per boe is calculated by dividing revenue (including realized loss on financial instruments) less royalties, operating and transportation costs by the total production of the Company measured in boe.
(2) Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed.
(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 6 of the Company's management's discussion and analysis for the Q4 and fiscal year ended March 31, 2018.

Basis of Presentation

This MD&A is for the three and twelve months ended March 31, 2018 and 2017 and should be read in conjunction with Bengal's consolidated financial statements and related notes for the years ended March 31, 2018 and 2017. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from January 1, 2018 through March 31, 2018. The terms "prior year's quarter" and "2018 quarter" are used throughout the MD&A for comparative purposes and refer to the period from Jan 1, 2017 through March 31, 2017. The terms "prior quarter", "preceding quarter" and "previous quarter" refer to the three months ended December 31, 2017.

The fiscal year for the Company is the twelve-month period ended March 31, 2018. The terms "fiscal 2018," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2017 through March 31, 2018. The terms "previous year," "prior year" and "fiscal 2017" are used in the MD&A for comparative purposes and refer to the period from April 1, 2016 through March 31, 2017. The term YTD means year-to-date.

The following abbreviations are used in this MD&A: boepd means barrels of oil equivalent per day; bpd means barrels per day; mcfpd means thousand cubic feet of natural gas per day; $/boe means Canadian dollars per boe; and NGL means natural gas liquids.

Non-IFRS Measurements

Within the MD&A, references are made to terms commonly used in the oil and gas industry. Netbacks, funds from operations per share, adjusted net earnings and adjusted net earnings per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Netbacks equal total revenue (including realized losses/gains on financial instruments) less royalties and operating and transportation expenses calculated on a boe basis. Management utilizes these measures to operational performance. Funds from operations per share is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed. Adjusted net earnings 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 earnings equal net income (loss) less unrealized losses/gains on foreign exchange and unrealized losses/gains on financial instruments plus non-cash impairment of non-current assets. Adjusted net earnings per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

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

	Three Months Ended March 31			Twelve Months Ended March 31		
($000s)	**2018**	2017	% Change	**2018**	2017	% Change
Net income (loss)	**(12,526)**	1,931	(749)	**(12,271)**	(2,768)	343
Unrealized loss (gain) on financial instruments	**(39)**	241	(116)	**1,661**	6,308	(74)
Unrealized foreign exchange loss (gain)	**255**	(991)	(126)	**(98)**	65	(251
Non-cash impairment of non-current assets	**12,167**	-	-	**12,167**	-	-
Adjusted net earnings (loss)	**(143)**	1,181	(112)	**1,459**	3,605	(60)

The adjusted net loss of $0.143 million and adjusted net earnings of $1.459 million for the three months ended and fiscal year ended 2018 represented net income (loss) adjusted for unrealized loss (gain) on financial instruments and foreign exchange as well as the non-cash impairment of non-current assets taken in Q4 fiscal 2018.

RESULTS OF OPERATIONS

Production, Commodity Pricing and Sales

Production	Three Months Ended March 31			Twelve Months Ended March 31		
	2018	2017	% Change	**2018**	2017	% Change
Oil Production (bpd)	**334**	344	(3)	**360**	379	(5)
Oil Production (bbls)	**30,050**	30,951	(3)	**131,455**	138,360	(5)

Crude oil production declined marginally in Q4 fiscal 2018 vs Q4 fiscal 2017. Total production during the quarter was 30,050 bbls (334 bbl/d) vs 30,951 bbls (344 bbl/d) in Q4 fiscal 2017. For the twelve months fiscal 2018, total production was 131,455 bbls (360 bbl/d) vs 138,360 (379 bbl/d) for the twelve months fiscal 2017.

Pricing

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. This premium is from marketing contracts negotiated on behalf of the Joint Venture by the current operator that took effect on July 1, 2017.

Realized crude oil prices increased 32% and increased 21% compared to the prior quarter and Q4 fiscal 2017 respectively. The increases are due to the strengthening US Brent commodity price on a year-over-year basis.

The following table outlines average benchmark prices compared to Bengal's realized prices:

Prices and Marketing	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
Average Benchmark Price	**2018**	2017	% Change	**2018**	2017	% Change
Bengal realized crude oil price before realized gain (loss) on financial instruments($CAD/bbl)	**$92.61**	$ 70.40	32	**$81.47**	$ 67.17	21
Realized gain (loss) on financial Instruments ($CAD/bbl)	**(9.58)**	31.37	(131)	**4.32**	34.06	(87)
Brent oil ($CAD/bbl)	**86.61**	71.18	18	**74.23**	63.88	16
Brent oil ($US/bbl)	**66.81**	53.78	24	**57.57**	48.66	18
Number of CAD$ for 1 AUS$	**0.99**	1.00	(1)	**0.99**	0.99	-
Number of CAD$ for 1 US$	**1.26**	1.32	(5)	**1.28**	1.31	(2)

Netbacks

Netbacks	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2018	2017	% Change	**2018**	2017	% Change
($000s)						
Oil sales	**2,783**	2,179	28	**10,710**	9,294	15
Realized gain (loss) on financial instruments	**(288)**	971	(130)	**568**	4,712	(88)
Royalties	**136**	(347)	(139)	**642**	(213)	(401)
Operating and transportation expenses	**1,077**	987	9	**3,718**	4,864	(24)
Netback ($000s)	**1,282**	2,510	(49)	**6,918**	9,355	(26)
Oil sales ($/bbl)	**92.61**	70.40	32	**81.47**	67.17	21
Realized gain (loss) on financial instruments ($/bbl)	**(9.58)**	31.37	(131)	**4.32**	34.06	(87)
Royalties ($/bbl)	**4.53**	(11.21)	(140)	**4.88**	(1.54)	(417)
Operating and transportation expenses ($/bbl)	**35.84**	31.89	12	**28.28**	35.15	(20)
Netback ($/bbl)	**42.66**	81.09	(47)	**52.63**	67.62	(22)

During the fourth quarter of fiscal year (FY) 2018, the Company realized a significant increase in its oil sales per barrel compared to Q4 FY 2017. The primary factor was the strong underling US Brent price for Q4 FY 2018. The average US Brent price for the quarter was US$ 66.81/bbl vs US$ 53.78/bbl in Q4 FY 2017. When the average premium to Brent is factored in, CAD$ 6 per barrel is added to the average base revenue price of CAD$ 86.61/bbl to arrive at CAD$ 92.61. Similarly, the twelve month FY 2018 is stronger than the twelve month FY 2017 due to the improvement in US Brent pricing. Full year 2018 saw US Brent average US$ 57.57/bbl compared to US$ 48.66/bbl for FY 2017. This in turn reflects a CAD$ 81.47/bbl average FY 2018 price compared to average CAD$ 67.17/bbl for FY 2017. In terms of netbacks, the Company realized a reduction in netback per barrel both in Q4 fiscal 2018 and full year 2018 due to realized losses on financial instruments. Throughout fiscal 2017, the Company realized large gains on financial instruments due to its US$ 80/bbl hedges when the average US Brent price was US$ 49.88/bbl compared to the US$ 47 hedges in fiscal 2018 when the average US Brent price was US$ 57.85/bbl. Operating costs per barrel are higher in the three months ended 2018 than previous quarters and previous year as no audit recoveries were realized in the quarter but expected in Q1 fiscal 2019.

Risk Management Activities

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

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

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, 2018 – December 31, 2018	Oil - Swap	34,572	47.00	47.00
April 1, 2018 – December 31, 2018	Oil – Put option	30,689	47.00	-
Time Period	**Type of Contract**	**Quantity Contracted (bbls)**	**Price Floor (US$/bbl)**	**Price Ceiling (US$/bbl)**
Jan. 1, 2019 – March 31, 2019	Oil - Swap	7,953	55.40	55.40
Jan. 1, 2019 – March 31, 2019	Oil – Put option	7,953	55.40	-

The fair value of the financial contracts outstanding as at March 31, 2018 is an estimated liability of $1.0 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

For the three months ended March 31, 2018, the derivative commodity contracts resulted in a realized loss of $0.3 million (Q4 fiscal 2017 - $1.0 million gain) and an unrealized loss of $0.4 million (Q4 fiscal 2017 - $0.2 million loss).

The realized and unrealized losses incurred in the current quarter were the result of the below-market hedges currently in place and the increase in Brent forward strip pricing. The realized gain in Q4 fiscal 2017 was the result of the US$ 80 per barrel oil swaps that have now expired.

Royalties

Royalties ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2018	2017	% Change	**2018**	2017	% Change
Royalty expense	**136**	(347)	(139)	**642**	(213)	(401)
$/bbl	**4.53**	(11.21)	(140)	**4.88**	(1.54)	(417)
% of revenue	**5**	(16)	(131)	**6**	(2)	(400)

In Australia, oil royalties are based on a government-established rate of 10% plus a Native Title royalty, which is typically 1%. The royalty rate is applied to gross revenues after deducting an allowance for allowable capital, transportation and operating costs, resulting in an effective rate of approximately 6% of gross revenue.

Royalties have increased compared to Q4 fiscal 2017 due to a one time significant credit received for reduction of allowable capital deductions during Q4 fiscal 2017 and due to lower recent drilling activity. For the fiscal year 2018, Royalty expenses have been impacted in the same manner as the Q4 fiscal year 2018. Overall, deductible allowances are down compared to fiscal year 2017 and Royalties as a percentage of revenue are more in line with the 6% expectation.

Operating & Transportation Expenses

Operating & trans. expenses ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2018	2017	% Change	**2018**	2017	% Change
Operating	**151**	53	185	**(239)**	563	(142)
Transportation	**926**	934	(1)	**3,957**	4,301	(8)
	1,077	987	9	**3,718**	4,864	(24)
Operating - $/boe	**5.02**	1.71	194	**(1.82)**	4.07	(145)
Transp. - $/boe	**30.82**	30.18	2	**30.10**	31.08	(3)
	35.84	31.89	12	**28.28**	35.15	(20)

Operating costs increased in Q4 of fiscal 2018 due to extra well work-overs and pump changes compared to Q4 of fiscal 2017. The lower operating costs for twelve months fiscal 2018 are due to the recovery of $1.1 million from an ongoing joint venture audit. These recoveries also explain the 142% decrease in YTD fiscal 2018 operating cost per barrel as compared to fiscal 2017.

Transportation costs on a per boe basis have increased 2% compared to Q4 fiscal 2017 but have decreased in FY 2018 by 3% compared to FY 2017 as the Company is realizing some cost reductions in transportation tariffs due to the previously disclosed new transportation tariff reductions that are now taking effect.

General and Administrative (G&A) Expenses and Share-based Compensation (“SBC”)

G&A Expenses and SBC ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2018	2017	% Change	**2018**	2017	% Change
Net G&A	**614**	721	(15)	**2,398**	2,740	(12)
Capitalized G&A	**69**	83	(17)	**295**	338	(13)
Total G&A	**683**	804	(15)	**2,693**	3,078	(13)
Expensed share-based compensation	**28**	4	600	**95**	29	228
Capitalized share-based compensation	**5**	1	400	**15**	7	114
Total share-based compensation	**33**	5	560	**110**	36	206

The 15% decrease in net G&A expenditures compared to Q4 2017 is a result of the Company focusing on limiting discretionary spending. Similarly on a full year fiscal 2018 basis, G&A costs were 12% less than in fiscal year 2017 due to cost management.

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries. Options granted in July 2015 and June 2017 vest conditionally based on certain performance criteria on their first, second and third anniversaries. The increase in share-based compensation expense reflects the issuance of the June 2017 option grant.

Impairment

The Company has taken a total impairment charge of $12.167 million. The majority of the impairment charge is against the Company’s ATP 732 asset. Due to certain leases expiring over the next two years with the

Company having no intention of developing or renewing these leases, the carrying value of ATP 732 was written down to $5.38 million.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2018	2017	% Change	**2018**	2017	% Change
PNG – Australia	**573**	443	29	**2,026**	2,291	(12)
Corporate	**3**	4	(25)	**14**	18	(22)
Total	**576**	447	29	**2,040**	2,309	(12)
$/boe – PNG Australia	**19.17**	14.31	34	**15.41**	16.56	(7)

The increase in depletion per barrel from Q4 fiscal 2017 is due to a 9% decline in reserves for the comparative quarter. The decrease in depletion per barrel for the twelve months ended March 31, 2018 is due to a 26% decline in the expected future costs associated with developing the proved and probable reserves and that the decline in reserves only impacts Q4 2018.

Finance Income/Expenses

Finance Income/Expenses ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2018	2017	% Change	**2018**	2017	% Change
Interest income	**1**	8	(88)	**13**	12	8
Accretion expense on decommissioning liabilities	**(9)**	(10)	(10)	**(37)**	(37)	-
Letter of credit charges	**-**	-	-	**-**	(55)	(100)
Interest on credit facility	**(236)**	(178)	33	**(954)**	(947)	1
Total	**(244)**	(180)	36	**(978)**	(1,027)	(5)

Interest on the credit facility is based on US dollar Libor + 3.2% margin.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2018	2017	% Change	**2018**	2017	% Change
Geological and geophysical	**1,586**	230	590	**2,139**	883	142
Drilling	**-**	(53)	(100)	**(52)**	2,974	(102)
Completions	**(1,156)**	504	(329)	**915**	1,761	(48)
Acquisition	**509**	-	-	**509**	-	-
Total expenditures	**939**	681	38	**3,511**	5,618	(38)
Exploration & evaluation expenditures	**1,996**	97	1,958	**2,277**	407	1,996
Development & production expenditures	**(1,057)**	584	(281)	**1,234**	5,211	(76)
Total net expenditures	**939**	681	38	**3,511**	5,618	(38)

The addition of $509 thousand of acquisition costs, in Q4 fiscal year 2018, is a result of acquiring the final 30% interest in ATP 934 bringing the Company's ownership to 100%. Capital expenditures are down overall in fiscal year 2018 due to a reduction in the drilling program compared to FY 2017. The credit balances for drilling completions of $1.2 million and development & production expenditures of $1.1 in the three months ended March 31, 2018 are both due to the reclassification of $1.4 million of costs from plant and natural gas properties back to exploration and evaluation assets related to the Chookola well program.

CREDIT FACILITY

In October 2014, Bengal closed its US $25.0 million secured credit facility with Westpac Institutional Bank ("Westpac") and placed an initial draw on November 12, 2014 of US $14.0 million. On August 26, 2016 following a US $1.5 million repayment, the Company extended the credit facility by 18 months to December 2018 with a borrowing base of US $15 million. On September 25, 2017, the Company extended the credit facility to December 2019 with a borrowing base of US $12.5 million. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US Libor plus 3.2%. Based on the extension, the Company is committed to extending its hedge contracts through December 2019 prior to June 30, 2018.

The credit facility is structured as a reserves-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. The reduction schedule commences on June 30, 2018 and occurs every six months thereafter until December 31, 2019 with a nominal reduction of US $2.5 million to the facility limit at each calculation date (through June 30, 2019) based on the Company's existing reserve profile and a nominal reduction of US $5 million at December 31, 2019. The facility limit at March 31, 2018 is US $12.5 million, of which US $12.5 million is currently drawn.

The credit facility's reserve based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the credit facility. The Company was in compliance with the stated covenants at March 31, 2018.

On March 5, 2018, Westpac agreed to amend the terms of the 2nd Extension Agreement dated September 25, 2017. Previously, the terms required Bengal to make principal payments on its facility of US $2.5 million US on June 30, 2018 and US $2.5 million US on December 31, 2018. The new amendment will defer the full amount of the June 30, 2018 payment into the second half of 2019 and the December 2018 principal payment has been reduced to US $1.5 million US. The balance of the December 2018 payment will also be deferred until the second half of 2019. In return Bengal has agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement which requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve base review by April 30, 2019.

SHARE CAPITAL

At June 8, 2018 there were 102,266,694 common shares issued and outstanding, together with 4,852,500 outstanding options.

Trading History	**Three Months Ended March 31**			**Twelve Months Ended March 31**		
	2018	2017	% Change	**2018**	2017	% Change
High	**$0.13**	$ 0.23	(43)	**$0.17**	$ 0.24	(29)
Low	**$0.09**	$ 0.13	(31)	**$0.08**	$ 0.11	(27)
Close	**$0.10**	$ 0.14	(29)	**$0.10**	$ 0.14	(29)
Volume (000s)	**2,800**	3,546	(21)	**15,454**	12,725	21
Shares outstanding (000s)	**102,267**	102,267	-	**102,267**	102,267	-
Weighted average shares outstanding (000s)						
Basic	**102,267**	102,267	-	**102,267**	76,770	33
Diluted	**102,267**	102,267	-	**102,267**	76,770	33

LIQUIDITY 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 accounts payable and accrued liabilities, credit facility and fair value of financial instruments and amounted to $19.3 million at March 31, 2018 (March 31, 2017 - $18.1 million).

At March 31, 2018, the Company had working capital of $3.4 million, including cash and cash equivalents of $3.9 million and restricted cash of $0.1 million, compared to working capital of $3.8 million at March 31, 2017. The Company has no available undrawn debt capacity under its Westpac credit facility.

The majority of the Company's oil sales are benchmarked on Brent prices which averaged US $57.57/bbl for the twelve months ended March 31, 2018. 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 (as required by Westpac) to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where appropriate. Under the current commodity price environment, the Company has no plans to use its internal source of cash to fund exploration activities. These are expected to be financed through farm-out or alternative financing sources.

The table below indicates the payment schedule for the credit facility:

Credit facility (US$000s)	
Fiscal year 2019	1,500
Fiscal year 2020	11,000
	12,500

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 fiscal Q4 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS $311,221 cash and potential future cash payments of up to AUS $1,000,000, which is made up of a AUS $200 thousand on certification by an independent competent person appointed by the Buyer of not less than 25 billion cubic feet of Proved Reserves and AUS $800 thousand due upon the delivery of First Gas to market.. Work program consists of 200 kilometers of 3D seismic and up to three wells.

AFE commitments are reflected where the Company has agreed with partners to proceed with activities (e.g. onshore Australia ATP 752 Cuisinier). The costs of these activities are based on minimum work budgets included in bid documents and agreements among joint venture parties, and have not been provided for in the financial statements. Actual costs may vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 934P	200 km^2 of 2D seismic and up to three wells	March 2021	$13.4

(1) Translated at March 31, 2018 at an exchange rate of AUS $1.00 = CAD $0.9898.

OTHER

At March 31, 2018, the contractual obligations for which the Company is responsible are as follows:

Contractual Obligations ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 893	$ 155	$ 311	$ 315	$ 112
Decommissioning obligations	1,556	-	60	175	1,321
Total contractual obligations	$ 2,449	$ 155	$ 371	$ 490	$ 1,433

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

($000s, except per share amounts)	**Mar. 31 2018**	**Dec. 31 2017**	Sep. 30 2017	Jun. 30 2017	Mar. 31 2017	Dec. 31 2016	Sep. 30 2016	Jun. 30 2016
Fiscal quarter	**Q4 2018**	**Q3 2018**	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Petroleum and natural gas sales	**2,783**	**3,211**	2,410	2,306	2,179	2,325	2,301	2,489
Cash from operations	**858**	**431**	648	1,690	643	934	1,982	956
Funds from operations	**525**	**1,268**	110	1,834	1,639	1,412	1,797	1,348
Per share								
Basic and diluted (1)	**0.01**	**0.01**	0.00	0.02	0.02	0.02	0.03	0.02
Net income (loss)	**(12,526)**	**206**	(500)	549	1,931	(2,288)	325	(2,736)
Per share								
Basic and diluted	**(0.12)**	**0.00**	0.00	0.01	0.02	(0.03)	0.00	(0.04)
Capital expenditures	**939**	**342**	1,527	703	681	1,234	3,320	383
Working capital (deficiency)	**3,385**	**(637)**	2,107	(2,477)	3,815	3,291	4,421	(9,171)
Total assets	**45,714**	**56,932**	56,032	57,104	57,706	56,020	55,552	54,108
Shares outstanding (000s)	**102,667**	**102,267**	102,267	102,267	102,267	102,267	68,178	68,178
Operations								
Oil Volumes (bpd)	**334**	354	383	369	344	355	386	431
Netback ($/boe)	**42.66**	63.13	28.97	49.80	81.09	69.01	67.30	56.09

(1) See “Non-IFRS Measurements” on page 6 of this MD&A.

Production over the last eight quarters peaked during Q1 fiscal 2017 as incremental production from the fiscal 2016 fracture stimulation program came on stream. Production increased in the Q1 and Q2 fiscal 2018 quarters as the wells from the Cuisinier fiscal 2017 drilling campaign were put on stream. Variances in net income have been impacted by unrealized gains/losses on foreign exchanges and derivative contracts as well as material impairments recorded in Q4 fiscal 2016 and Q4 fiscal 2018.

Fluctuations in netbacks have been primarily driven by volatile benchmark crude prices and associated hedging gains and losses as royalties and operating and transportation costs have remained consistent (with the exception of the joint venture audit proceeds). Joint venture audit proceeds received during Q1 and Q3 fiscal 2018 contributed to increased funds from operations and cash flows in that period.

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, 2018 due to the material weaknesses noted below.

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

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

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

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

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

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.

i. 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.

ii. 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 and PP&E assets required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

iii. Recognition of deferred income tax assets

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

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 the assets and liabilities.

i. 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.

ii. 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.

iii. 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.

iv. 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: expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

NEW ACCOUNTING STANDARDS AND PRONOUNCEMENTS

New standards and interpretations not yet adopted

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

Revenue from contracts with customers

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers*, which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts* and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue; at appoint in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Company will adopt the standard for its fiscal year commencing April 1, 2018, using the retrospective approach. Based on the Company's review of contracts with customers, at this time, the Company does not anticipate that the adoption of IFRS 15 will have a material impact on net income (loss) and financial position. However, the Company is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. The Company does anticipate expanding disclosures in the notes to its consolidated financial statements as described by IFRS 15.

Financial instruments: recognition and measurement

In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 9 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bengal intends to adopt IFRS 9 on a retrospective basis on April 1, 2018. The Company determined that there will not by any material changes to the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The Company does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

Leases

In January 2016, the IASB issued IFRS 16 *Leases*. This standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than 12 months. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 *Revenue from Contracts with Customers* at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

RISK FACTORS

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

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

Exploration, Development and Production Risks

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

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

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

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

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

Risks Associated with Foreign Operations

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

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

Substantial Capital Requirements and Liquidity

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

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

Health, Safety and Environment

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

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

Insurance

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

Competition

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

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

ADDITIONAL INFORMATION

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

Forward-looking Statements - *Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward-looking statements. 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, or incorporated by reference into, this MD&A should not be unduly relied upon.*

In particular, this Management's Discussion and Analysis, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *The expected timing of the frac program on Barta Block Cuisinier;*
- *The expected timing of the spudding of Chookola well on Barta Block Cuisinier and timing to complete evaluation of all associated the target zones;*
- *The presence of a gas resource play on ATP 934 Barrolka permit;*
- *The timing of the development of the Nubba-1 well discovery on the Yilgarn PCA, ATP 752, Wompi Block;*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *The Company expects netbacks to remain above $60/bbl under current market conditions;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs; and*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements.*

With respect to the forward looking statements contained in the MD&A, Bengal has made assumptions regarding: future commodity prices; the impact of royalty regimes; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital; the continued availability of undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Unable to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Changes in income tax laws or changes to royalty and environmental regulations relating to the oil and gas industry;*
- *The risk that Bengal may not be successful in raising funds by an equity issue; 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 and the documents incorporated by reference herein 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).

These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be.

Consolidated Financial Statements

Years Ended
March 31, 2018 and 2017

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, 2018. 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.

We have audited the accompanying consolidated financial statements of Bengal Energy Ltd., which comprise the consolidated statements of financial position as at March 31, 2018 and March 31, 2017, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Bengal Energy Ltd. as at March 31, 2018 and March 31, 2017, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants
June 8, 2018
Calgary, Canada

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2018	2017
ASSETS			
Current assets:			
Cash and cash equivalents	3	$ 3,904	$ 3,903
Restricted cash		140	140
Accounts receivable		4,307	3,575
Prepaid expenses and deposits		154	193
Fair value of financial instruments	12	-	820
		8,505	8,631
Non-current assets:			
Exploration and evaluation assets	4	10,102	20,529
Petroleum and natural gas properties	5	27,107	28,546
		37,209	49,075
Total assets		$ 45,714	$ 57,706
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		$ 2,232	$ 1,484
Current portion of credit facility	7	1,934	3,332
Fair value of financial instruments	12	954	-
		5,120	4,816
Non-current liabilities:			
Decommissioning liability	8	1,556	1,516
Credit facility	7	14,146	13,168
Fair value of financial instruments	12	-	102
		15,702	14,786
Shareholders' equity:			
Share capital	9	98,100	98,100
Contributed surplus		7,755	7,645
Accumulated other comprehensive income		1,034	2,085
Deficit		(81,997)	(69,726)
		24,892	38,104
Total liabilities and shareholders' equity		$ 45,714	$ 57,706

Commitments (note 15)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director
Chayan Chakrabarty

Director
James B. Howe

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	2018	2017
Income			
Petroleum and natural gas revenue		**$10,710**	$9,294
Royalties recovery (expense)		**(642)**	213
		10,068	9,507
Realized gain on financial instruments		**568**	4,712
Unrealized loss on financial instruments		**(1,661)**	(6,308)
		8,975	7,911
Operating expenses			
General and administrative		**2,398**	2,740
Operating and transportation		**3,718**	4,864
Depletion and depreciation	**5**	**2,040**	2,309
Impairment	**4**	**12,167**	-
Share-based compensation		**95**	29
		20,418	9,942
Operating loss		**(11,443)**	(2,031)
Other income (expenses)			
Other		**124**	378
Finance expenses	**11**	**(978)**	(1,027)
Foreign exchange gain (loss)		**26**	(88)
		(828)	(737)
Net loss		**(12,271)**	(2,768)
Exchange differences on translation of foreign operations		**(1,051)**	750
Total comprehensive loss for the year		**$(13,322)**	$(2,018)
Loss per share			
- Basic & diluted	**9**	**$(0.12)**	$(0.04)
Weighted average number of shares outstanding (000s)			
- Basic & diluted	**9**	**102,267**	76,770

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2016	68,177,796	$ 94,151	$ 167	$ 7,442	$ 1,335	$ (66,958)	$ 36,137
Net loss for the year	-	-	-	-	-	(2,768)	(2,768)
Comprehensive income for the year	-	-	-	-	750	-	750
Rights offering	34,088,898	4,091	-	-	-	-	4,091
Share issue costs	-	(142)	-	-	-	-	(142)
Expiry of warrants	-	-	(167)	167	-	-	-
Share-based compensation – expensed	-	-	-	29	-	-	29
Share-based compensation – capitalized	-	-	-	7	-	-	7
Balance at March 31, 2017	102,266,694	$ 98,100	$ -	$ 7,645	$ 2,085	$ (69,726)	$ 38,104
Balance at April 1, 2017	**102,266,694**	**$ 98,100**	**$ -**	**$ 7,645**	**$2,085**	**$ (69,726)**	**$ 38,104**
Net loss for the year	**-**	**-**	**-**	**-**	**-**	**(12,271)**	**(12,271)**
Comprehensive loss for the year	**-**	**-**	**-**	**-**	**(1,051)**	**-**	**(1,051)**
Share-based compensation – expensed	**-**	**-**	**-**	**95**	**-**	**-**	**95**
Share-based compensation – capitalized	**-**	**-**	**-**	**15**	**-**	**-**	**15**
Balance at March 31, 2018	**102,266,694**	**$ 98,100**	**$ -**	**$ 7,755**	**$ 1,034**	**$ (81,997)**	**$ 24,892**

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31,	Notes	2018	2017
Operating activities			
Net loss for the year		**$ (12,271)**	$ (2,768)
Non-cash items:			
Depletion and depreciation		**2,040**	2,309
Impairment		**12,167**	-
Accretion on decommissioning liability		**37**	37
Accretion on credit facility		**230**	278
Share-based compensation		**95**	29
Loss (profit) on disposition of petroleum and natural gas properties		**(124)**	62
Unrealized loss on financial instruments		**1,661**	6,308
Unrealized foreign exchange (gain) loss		**(98)**	65
Funds from operations		**3,737**	6,196
Change in non-cash working capital	**14**	**(110)**	(1,681)
Net cash from operating activities		**3,627**	4,515
Investing activities			
Exploration and evaluation expenditures	**4**	**(2,277)**	(407)
Petroleum and natural gas properties	**5**	**(1,234)**	(5,211)
Changes in non-cash working capital	**14**	**208**	(178)
Net cash used in investing activities		**(3,303)**	(5,796)
Financing activities			
Proceeds from issuance of shares, net of issuance costs	**9**	**-**	(3,949)
Repayment of credit facility	**7**	**-**	(1,984)
Facility extension fees	**7**	**(95)**	(150)
Changes in non-cash working capital	**14**	**(109)**	285
Net cash (used in) from financing activities		**(204)**	2,100
Impact of foreign exchange on cash and cash equivalents		**(119)**	74
Net increase in cash equivalents		**1**	893
Cash and cash equivalents, beginning of year		**3,903**	3,010
Cash and cash equivalents, end of year		**$ 3,904**	$ 3,903

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 for and development and production of oil and gas reserves in Australia, India and Canada. The consolidated financial statements (the "financial statements") of the Company as at March 31, 2018 and 2017 and for the years then ended are comprised of the Company and its wholly-owned subsidiaries including Bengal Energy International Inc. and Bengal Energy Australia (Pty) Ltd., which are incorporated in Canada and Australia respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

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

2. BASIS OF PREPARATION

a) Statement of compliance

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

The financial statements were approved and authorized for issuance by the Board of Directors on June 8, 2018.

b) Basis of measurement

These financial statements have been prepared on a historical cost basis, except for commodity contracts as discussed in Note 12.

c) Functional and presentation currency

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

3. CASH AND CASH EQUIVALENTS

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

As at ($000s)	March 31, 2018	March 31, 2017
Cash and bank balances	**3,897**	1,655
Short-term deposits	**7**	2,248
	3,904	3,903

4. EXPLORATION AND EVALUATION ASSETS (E&E ASSETS)

($000s)	
Balance at April 1, 2016	19,626
Additions	407
Capitalized share-based compensation	3
Exchange adjustments	493
Balance at March 31, 2017	20,529
Additions	**1,768**
Acquisition	**509**
Capitalized share-based compensation	**7**
Impairment	**(12,167)**
Exchange adjustments	**(544)**
Balance March 31, 2018	**10,102**

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.

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

($000s)	**Australia**
ATP 732P – Tookoonooka	16,573
ATP 752P – Barta Cuisinier	1,273
ATP 934P – Barrolka	1,114
Other[(1)]	1,569
March 31, 2017	20,529
($000s)	**Australia**
ATP 732P – Tookoonooka	5,380
ATP 752P – Barta Cuisinier	2,725
ATP 934P – Barrolka	1,852
Other[(1)]	145
March 31, 2018	**10,102**

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

In fiscal Q4 2018, the Company consolidated its ownership of ATP 934 and now owns and controls operatorship of a 100% working interest. The purchase consideration was AUS$ 311,221 cash and potential future cash payments of up to AUS$ 1,000,000, subject to certain conditions and commercial benchmarks being achieved (see Note 15).

The Company recorded an impairment charge of $12.17 million against the Company's ATP 732 asset due to certain leases expiring over the next two years that the Company has no intention of developing or renewing. These impairment charges were taken into the Consolidated Statement of Loss in fiscal Q4, 2018.

5. PETROLEUM AND NATURAL GAS PROPERTIES

$000s	Petroleum and Natural Gas Properties	Corporate Assets	Total
Cost:			
Balance at April 1, 2016	41,820	344	42,164
Additions	5,211	-	5,211
Capitalized share-based compensation	4	-	4
Change in decommissioning obligation	80	-	80
Exchange adjustments	760	-	760
Balance at March 31, 2017	47,875	344	48,219
Additions	**1,234**	**-**	**1,234**
Disposals	**(4,316)**	**-**	**(4,316)**
Capitalized share-based compensation	**8**	**-**	**8**
Change in decommissioning obligation	**167**	**-**	**167**
Exchange adjustments	**(732)**	**-**	**(732)**
Balance at March 31, 2018	**44,236**	**344**	**44,580**

$000s	Petroleum and Natural Gas Properties	Corporate Assets	Total
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2016	17,020	269	17,289
Depletion and depreciation charge	2,291	18	2,309
Exchange adjustments	75	-	75
Balance at March 31, 2017	19,386	287	19,673
Depletion and depreciation charge	**2,026**	**14**	**2,040**
Disposals	**(4,316)**	**-**	**(4,316)**
		-	
Exchange adjustments	**76**	**-**	**76**
Balance at March 31, 2018	**17,172**	**301**	**17,473**
Net carrying value			
At March 31, 2017	28,489	57	28,546
At March 31, 2018	**27,064**	**43**	**27,107**

The calculation of depletion for the quarter ended March 31, 2018 included $58.1 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2017 - $73.4 million).

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

6. 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:

Years Ended March 31,	2018	2017
($000s)		
Loss before taxes	(12,271)	(2,768)
Statutory tax rate	27%	27%
Expected income tax recovery	(3,313)	(747)
Foreign exchange	(403)	(269)
Stock-based compensation	26	8
Effect of change in tax rate & other	(308)	(45)
Other	-	-
Changes in unrecognized tax asset	3,998	1,053
Income tax recovery	-	-

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

As of March 31,	2018	2017
($000s)		
Non-capital losses	46,135	32,915
Net capital losses	6,034	5,740
P&NG properties	12,983	13,150
Share issue costs	263	557
Decommissioning obligations	-	102
	65,415	52,464

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

As of March 31,	2018	2017
($000s)		
Property, plant & equipment	4,446	14,651
Fair value of financial instruments	(286)	216
Foreign exchange	(430)	(942)
Decommissioning obligations	(467)	(418)
Non-capital losses	(3,263)	(13,507)
	-	-

At March 31, 2018, the Company had approximately $30.3 million and $26.8 million of non-capital losses in Canada and Australia respectively (2017- $29.3 million and $48.7 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2026 to 2037. The Australian non-capital losses have no term to expiry. The Company's ongoing drilling activities continue to generate deferred assets related to Petroleum Resource Rent Tax ("PRRT") in its Australia 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, 2018, the Company has no deferred tax liabilities in respect of these temporary differences.

7. CREDIT FACILITY

Facility Agreement – Issued November 12, 2014 ($000s)		
Gross proceeds		15,364
Total cash fees		(994)
Repayment		(1,984)
		12,386
Unrealized foreign exchange loss		3,238
Accretion		876
Balance at March 31, 2017		**16,500**
Facility extension fees		**(95)**
Unrealized foreign exchange gain		**(555)**
Accretion		**230**
Balance at March 31, 2018		**16,080**
	March 31, 2018	**March 31, 2017**
Current portion of credit facility	**1,934**	3,332
Non-current portion of credit facility	**14,146**	13,168

In October 2014, Bengal closed its US $25.0 million secured credit facility with Westpac Institutional Bank ("Westpac") and placed an initial draw on November 12, 2014 of US $14.0 million. On August 26, 2016 following a US $1.5 million repayment, the Company extended the credit facility by 18 months to December 2018 with a borrowing base of US $15 million. On September 25, 2017, the Company extended the credit facility to December 2019 with a borrowing base of US $12.5 million. On March 5, 2018 the Credit Agreement was further amended to delay the majority of principle payments into 2019. The facility is secured by the Company's producing assets in the Cuisinier field in Australia's Cooper Basin, has a five and one-half year term and carries an interest rate of US Libor plus 3.2%.

The credit facility is structured as a reserves-based revolving facility under a predetermined reduction schedule, to be evaluated based on existing reserves at each calculation date. Under the Amendment dated March 5, 2018 the Company is required to make a US$ 1.5 million principle payment on December 31, 2018 and a further US$ 5 million on June 30, 2019 and US$ 6 million on December 30, 2019. In return, the Company has agreed to amend the debt service coverage ratio covenant definition, provide for a cash sharing arrangement which requires the Company to deposit 50% of free cash flow against the outstanding loan amount and agree to a reserve base review by April 30, 2019.

The credit facility's reserve-based covenants include a debt service coverage ratio (cash available for debt payments divided by mandatory debt repayments) as well as a loan life coverage ratio (net present value of future cash available for debt service divided by the available facility). These covenants impact the Company's available facility limit, and therefore the ability to secure its debt as a percentage of reserve forecasts and are evaluated at each calculation date. These covenants are calculated using inputs as prescribed by Westpac, and a default event triggered by a breach of covenants may result in a full redemption of all outstanding borrowings under the terms of the credit facility. The Company was in compliance with the stated covenants at March 31, 2018.

8. DECOMMISSIONING AND RESTORATION LIABILITY

The total decommissioning and restoration obligations were estimated by management based on the estimated costs to reclaim and abandon the wells, well sites and certain facilities based on the Company's contractual requirements.

Changes to decommissioning and restoration obligations were as follows:

March 31,	2018	2017
($000s)		
Decommissioning liabilities, beginning of year	**1,516**	1,422
Change in estimate net of disposals	**43**	(259)
Additions	**-**	278
Accretion	**37**	37
Exchange adjustments	**(40)**	38
Decommissioning liabilities, end of year	**1,556**	1,516

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, 2018 is approximately $2.2 million (March 31, 2017 – $2.3 million) which will be incurred between 2020 and 2046. An inflation factor of 1.9% and a risk-free discount rate of 2.6% have been applied to the decommissioning liability at March 31, 2018.

9. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares with no par value.

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

(b) Issued:

The following provides a continuity of share capital:

($000s)	Number of Shares	Amount
Balance at March 31, 2016	**68,177,796**	**94,151**
Issued on exercise of rights offering	**34,088,898**	**4,091**
Share issue costs	**-**	**(142)**
Balance at March 31, 2017 and 2018	**102,266,694**	**98,100**

The Company completed a rights offering (the "Rights Offering") which closed on December 29, 2016. Under the terms of the Rights Offering, each registered holder of common shares, at the close of business on December 2, 2016, received one Right for each common share held. Two Rights, plus the sum of $0.12 (the "Subscription Price"), entitled the holder thereof to acquire one common share. The Rights Offering resulted in 34,088,898 common shares being issued (16,056,853 common shares were issued to officers and directors) for total proceeds of $4.1 million. Share issuance costs of $142,000 were incurred related to the Rights Offering and have been recognized in the carrying value of share capital on the consolidated statement of financial position.

(c) Share-based compensation – stock options:

The Company has a share option plan for directors, officers, employees and consultants of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of three to five years and vest one-third immediately and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. Effective with the option grant on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries. Effective with the option grant of July 30, 2015, performance criteria were introduced, which allow for the vesting of stock options contingent on meeting pre-established targets based on internal and external metrics.

The Company accounts for its share-based compensation plan using the fair value method. Under this method, each grant results in three instalments. The fair value of the first instalment is charged to profit or loss immediately. The remaining two instalments are charged to profit or loss over their respective vesting period of one and two years respectively. For options that vest one-third each year on the first year anniversary, the fair value of the options are charged to profit and loss over the three year vesting period. Stock options granted under the plan can be exercised on a cashless basis, whereby the employee receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the employee so elects.

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2016	**4,357,000**	**$ 0.72**
Granted	**-**	**-**
Forfeited	-	-
Expired	**(1,655,000)**	**1.19**
Exercised	-	-
Outstanding at March 31, 2017	**2,702,500**	**$ 0.43**
Granted	**3,355,000**	**0.10**
Forfeited	**(543,853)**	**0.11**
Expired	**(911,147)**	**0.55**
Exercised	-	-
Outstanding at March 31, 2018	**4,602,500**	**$ 0.20**
Exercisable at March 31, 2018	**986,096**	**$ 0.52**

	Options Outstanding			Options Exercisable	
Option Price (1)	**Number Outstanding**	**Exercise Price (2)**	**Remaining Life (3)**	**Number Exercisable**	**Exercise Price (2)**
$0.10 - $0.46	3,852,500	$0.12	3.78	236,096	$0.18
$0.47 - $0.65	750,000	$0.63	0.32	750,000	$0.63
Total	**4,602,500**	**$0.20**	**3.21**	**986,096**	**$0.52**

(1) Range of option exercise prices
(2) Weighted average exercise price of options
(3) Weighted average remaining contractual life of options in years

The fair value of options granted during Q2 and Q3 fiscal 2018 were estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values:

Granted	3,330,000	25,000
Assumptions:		
Risk free interest rate (%)	1.13%	1.78%
Expected life (years)	5 yrs.	5 yrs.
Expected volatility (%)(1)	91%	92%
Estimated forfeiture rate (%)	20%	20%
Weighted average fair value of options granted	$0.07	$0.09
Weighted average share price on date of grant	$0.10	$0.125

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

The fair value of 3,330,000 and 25,000 stock options granted during Q2 and Q3 fiscal 2018 were approximately $187,000 and $2,000 respectively. No options were granted during the year ended

March 31, 2017.

(d) Per share amounts:

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

For the Year Ended	2018	2017
($000s)		
Loss for the year	**$ (12,271)**	$ (2,768)
(000s shares)		
Weighted average number of common shares (basic)	**102,267**	76,770
Weighted average number of common shares (diluted)	**102,267**	76,770
Basic and diluted loss per share	**$(0.12)**	$(0.04)

For the year ended March 31, 2018, there were 4,602,500 (March 31, 2017- 2,702,500) options considered anti-dilutive.

10. 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:

Year ended March 31,	2018	2017
($000s)		
Salaries & employee benefits	**977**	986
Share-based compensation(1)	**97**	33
General & administrative expenses	**1,074**	1,019

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

11. FINANCE INCOME/EXPENSES

Year ended March 31,	2018	2017
($000s)		
Interest income	**13**	12
Accretion on decommissioning obligations	**(37)**	(37)
Letter of credit charges	**-**	(55)
Interest on credit facility	**(954)**	(947)
Finance expenses	**(978)**	(1,027)

12. 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, 2018, Bengal's receivables consisted of $4.3 million (March 31, 2017 - $3.1 million) from joint venture partners (of which $1.3 million has been subsequently collected) and $nil million (March 31, 2017 - $0.4 million) of other trade receivables.

In Australia, production is purchased by a consortium led by one of Australia's largest public oil and gas companies which is also the operator of Bengal's production. Bengal has a Crude Oil Purchase Agreement with this 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, 2018 (March 31, 2017- $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, 2018 and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the year ended March 31, 2018 (March 31, 2017 – nil). Exposure to the carrying value of its financial instruments relates to the Company's commodity-based derivatives held by Westpac Banking Corporation, which carries a Standard & Poor's credit rating of AA-. Management considers the credit risk of these instruments to be adequately mitigated by the credit stating 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 accounts payable and accrued liabilities, fair value of financial instruments, and credit facility and amounted to $19.3 million at March 31, 2018 (March 31, 2017 - $18.1 million).

At March 31, 2018, the Company had working capital of $3.4 million, including cash and short-term deposits of $3.9 million and restricted cash of $0.1 million, compared to working capital of $3.8 million at March 31, 2017. The Company has no available undrawn debt capacity under its Westpac credit facility.

The majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where appropriate. Under the current commodity price environment, the Company plans to use its internal source of cash to fund exploration activities.

The table below indicates the current payment schedule for the credit facility:

Credit facility (US$000s)	
Fiscal year 2019	1,500
Fiscal year 2020	11,000
	12,500

(c) Market risk:

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates 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 exchange rate 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 U.S. dollars for Australian oil sales and incurs expenditures in Australian, Canadian and U.S. currencies. Having sales and expenditures denominated in three currencies spreads the impact of individual currency fluctuations.

The Company may enter into derivative foreign currency contracts in order to manage foreign currency exchange rate risk, but has not done so to date.

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

As at March 31, 2018 (CDN$000s)	**CAD**	**AUD**	**USD**	**Total**
Cash and cash equivalents	439	82	3,383	3,904
Restricted cash	140	-	-	140
Accounts receivable	15	4,292	-	4,307
Accounts payable and accrued liabilities	(327)	(1,905)	-	(2,232)
Credit facility	-	-	(16,080)	(16,080)
Fair value of financial instruments	-	-	(954)	(954)
	267	**2,469**	**(13,651)**	**(10,915)**

Commodity Price Risk

Commodity price risk is the risk that the fair value or 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, 2018, 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, 2018 – December 31, 2018	Oil - Swap	34,572	47.00	47.00
April 1, 2018 – December 31, 2018	Oil – Put option	30,689	47.00	-

($000s)	Oil - swap	Oil – put	Total
Current fair value of financial instruments	(894)	9	(885)
Non-current fair value of financial instruments	-	-	-
Total	**(894)**	**9**	**(885)**

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US$/bbl)	Price Ceiling (US$/bbl)
January 1, 2019 – March 31, 2019	Oil - Swap	7,953	55.40	55.40
January 1, 2019 – March 31, 2019	Oil – Put option	7,953	55.40	-

($000s)	Oil - swap	Oil – put	Total
Current fair value of financial instruments	(97)	28	(69)
Non-current fair value of financial instruments	-	-	-
Total	**(97)**	**28**	**(69)**

A US $1.00 increase in the future crude oil price per barrel would result in an approximate US $81,000 decrease in the fair value of financial instruments at March 31, 2018 while a US$ 1.00 decrease would result in an increase of approximately US $81,000 in the fair value of the instruments.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at March 31, 2018 as the funds are not invested in interest-bearing instruments. The Company's credit facility carries a floating interest rate based on quoted US dollar LIBOR rates. The Company had no interest rate derivatives at March 31, 2018.

For the year ended March 31, 2018, a 1% increase in US Libor would increase interest expense by $121,000.

13. 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.

14. CHANGES IN NON-CASH WORKING CAPITAL

Year ended March 31,	2018	2017
($000s)		
Accounts receivable	(732)	(388)
Prepaid expenses and deposits	39	38
Accounts payable and accrued liabilities	748	(1,185)
Impact of foreign exchange	(66)	37
Total	(11)	(1,574)
Relating to:		
Operating	(110)	(1,681)
Financing	(109)	285
Investing	208	(178)
Total	(11)	(1,574)

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

Year ended March 31 ($000s)	2018	2017
Cash interest paid	777	705
Cash interest received	13	12

15. COMMITMENTS

Pursuant to current production sharing contracts (“PSC”), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. Additional commitments are reflected where the Company has agreed with joint operating partners to proceed with activities. The costs of these activities are based on minimum work budgets included in bid documents and have not been provided for in the financial statements. Actual costs will vary from budget.

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 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$ 311,221 cash and potential future cash payments of up to AUS$ 1,000,000, which is made up of a AUS$ 200 thousand 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$ 800 thousand due upon the delivery of the first shipments of gas to market. Work program consists of 200 kilometers of 3D seismic and up to three wells.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 934P	200 km^2 of 3D seismic and up to three wells	March 2021	$13.4

(1) Translated at March 31, 2018 at an exchange rate of AUS $1.00 = CAD $0.9898.

At March 31, 2018 the Company had the following lease commitment for office space in Canada.

($000s)					
April 2018 to November 2023	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
Office lease	**893**	**155**	**311**	**315**	**112**

16. SEGMENTED INFORMATION

As at March 31, 2018, the Company has three reportable operating segments being the Australian and Indian 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.

For the year ended March 31, 2018 ($000s)				
	Australia	**Corporate**	**India**	**Total**
Revenue	10,710	-	-	10,710
Interest revenue	12	1	-	13
Interest expense	954	-	-	954
Depletion and depreciation	1,869	14	-	1,883
Net earnings (loss)	(11,205)	(1,056)	(10)	(12,271)
Exploration and evaluation expenditures	2,277	-	-	2,277
Petroleum and natural gas property expenditure.	1,234	-	-	1,234
Impairment	12,324	-	-	12,324
March 31, 2018 ($000s)				
Petroleum and natural gas properties				
Cost	44,236	344	-	44,580
Accumulated impairment loss	(797)	-	-	(797)
Accumulated depletion and depreciation	(16,375)	(301)	-	(16,676)
Net book value	27,064	43	-	27,107
Exploration and evaluation assets	31,410	-	8,140	39,550
Accumulated impairment losses	(21,308)	-	(8,140)	(29,448)
Net book value	10,102	-	-	10,102

For the ended March 31, 2017 ($000s)				
	Australia	Corporate	India	Total
Revenue	9,294	-	-	9,294
Interest income	11	1	-	12
Interest expense	947	-	-	947
Depletion and depreciation	2,291	18	-	2,309
Net earnings (loss)	(1,425)	(1,153)	(190)	(2,768)
Exploration and evaluation expenditures	407	-	-	407
Petroleum and natural gas property expenditures	5,211	-	-	5,211
March 31, 2017 ($000s)				
Petroleum and natural gas properties				
Cost	43,582	4,637	-	48,219
Accumulated impairment losses	(796)	(310)	-	(1,106)
Accumulated depletion and depreciation	(14,297)	(4,270)	-	(18,567)
Net book value	28,489	57	-	28,546
Exploration and evaluation assets	29,850	-	8,415	38,265
Accumulated impairment losses	(9,321)	-	(8,484)	(17,736)
Net book value	20,529	-	-	20,529

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

(e) Petroleum and natural gas properties

Carrying value

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

Subsequent costs

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

Depletion and depreciation

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

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

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

(f) Impairment

E&E 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 Development and Production (“D&P”) assets. 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 selling costs 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. For impairment losses identified based on a CGU, the loss is allocated on a pro rata basis to the assets within the CGU(s). 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 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 immediately 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 assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss ("FVTPL"), loans and receivables, held-to-maturity investments, available-for -sale financial assets, or other liabilities, as appropriate. Financial assets and liabilities are recognized initially at fair value.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets and liabilities are measured at fair value and changes in fair value are recognized in profit or loss. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive loss until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability classified as FVTPL are expensed immediately. For a financial asset or financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to or deducted from the fair value on initial recognition and amortized through profit or loss income over the term of the financial instrument.

(i) Non-derivative financial instruments

Cash and cash equivalents, restricted cash as well as accounts receivable are classified as loans and receivables, which are measured at amortized cost. Accounts payable and accrued liabilities, and the credit facility are classified as other financial liabilities, which are measured at amortized cost.

(ii) Derivative financial instruments

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

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

Fair value

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

Share capital

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

(h) Foreign currency translation:

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

(i) Share-based compensation:

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

(j) Revenue recognition:

Revenue from the sale of natural gas, natural gas liquids and crude oil is recognized when the significant risks and rewards of ownership are transferred, which is when title passes to the customer in accordance with the terms of the sales contract. This generally occurs when the product is physically transferred into a pipe, truck or other delivery mechanism.

(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 fees on Performance Security Guarantees issued by Export Development Canada, bank fees on Bank Guarantees issued to the Government of India, letter of credit charges, interest on notes payable and 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.

Financial instruments comprise cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, 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, accounts receivable, accounts payable and accrued liabilities

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

ii) Credit facility

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

iii) Derivatives

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

(o) New standards and interpretations not yet adopted:

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

Revenue from contracts with customers

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers*, which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue; at appoint in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Company will adopt the standard for its fiscal year commencing April 1, 2018, using the retrospective approach. Based on the Company's review of contracts with customers, at this time, the Company does not anticipate that the adoption of IFRS 15 will have a material impact on net income (loss) and financial position. However, the Company is still in the process of reviewing all of its contracts and fully assessing the financial statement impact. The Company does anticipate expanding disclosures in the notes to its consolidated financial statements as described by IFRS 15.

Financial instruments: recognition and measurement

In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 9 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bengal intends to adopt IFRS 9 on a retrospective basis on April 1, 2018. The Company determined that there will not by any material changes to the measurement and carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The Company does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

Leases

In January 2016, the IASB issued IFRS 16 *Leases*. This standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than 12 months. The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 *Revenue from Contracts with Customers* at or before the initial adoption date of January 1, 2018. The new standard is to be adopted either retrospectively or using a modified retrospective approach. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on April 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

18. 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.

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.

i) 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.

ii) 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.

iii) Recognition of deferred income tax assets

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

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.

i) 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.

ii) 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.

iii) 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.

iv) 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.

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