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.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

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

BANKERS

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

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

DIRECTORS

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

DISCLOSURE COMMITTEE

Chayan Chakrabarty
Matthew Moorman

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

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

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