International exploration & production

Management's Discussion & Analysis

Three and Six Months Ended
September 30, 2015 and 2014

SECOND QUARTER FISCAL 2016 HIGHLIGHTS

Operational Highlights:

- **Production tie-ins** – The Cuisinier 20 and Cuisinier 21 wells were brought on stream at the end of June at restricted rates and were on production throughout most of the quarter. Average production from these two wells was approximately 450 bopd (130 bopd net to the Company) as these wells continue to stabilize.

- **Production Volumes** – Production in the second quarter averaged 592 barrels of oil equivalent per day ("boepd"), a 14% increase from the preceding quarter and an increase of 30% from Q2 2015 due to an entire quarter of incremental production from the Cuisinier Phase One and Phase Two drilling programs.

- **Onshore India Drilling Plan –** At Bengal's onshore India block situated within the Cauvery Basin (CY-ONN-2005/1 – 30% WI), the Company continues to coordinate with its partners, Gas Authority of India Ltd. ("GAIL") and Gujarat State Petroleum Corporation, for the drilling of three exploration wells. GAIL, the operator, continues to negotiate with various stakeholders and government bodies that provide the necessary approvals to proceed. The drilling of the first of three exploration wells is expected to commence no earlier than late calendar 2015. The block is currently under force majeure subject to stakeholder negotiations, which was further extended on October 10, 2015.

Financial Highlights:

- **Revenues** – Bengal's revenue of approximately $3.4 million in the second quarter is 8% less than the $3.7 million generated in the preceding quarter due to decreased realized commodity prices. Revenues decreased 24% compared to the $4.5 million generated during Q2 2015 driven by lower commodity prices partially offset by increased production. Sales prices averaged USD $62/bbl before hedging, compared to average sales prices of USD $106/bbl during Q2 2015.

- **Hedging in place through June 2017** – the Company has approximately 196,000 barrels of production hedged with a floor price of US $80 per barrel through to June 2017. During the quarter ended March 31, 2015, realized gains of derivative financial instruments were $0.7 million. During the quarter, the Company sold 19,580 bbls at US $80 as part of its hedging program, which represents 41% of quarterly production.

- **Funds Flow from Operations[(1)]** – Bengal generated funds flow from operations of $1.3 million in the quarter ended September 30, 2015 a 8% increase from the $1.2 million generated in the preceding quarter and a 12% decrease from the $1.5 million recorded during Q2 2015.

- **Net Loss** – Bengal reported net income of $1.2 million for the quarter compared to a net loss of $1.3 million in the preceding quarter, and a net loss of $0.1 million in Q2 2015 primarily due to the impact of unrealized losses or gains on derivative contracts, which increased in value as Brent forward pricing decreased during the quarter. Excluding the impact of unrealized foreign exchange and unrealized hedging gains and losses, adjusted net loss[1] is $0.3 million for the second quarter of 2016 compared to an adjusted net income of 0.1 million in Q2 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS – November 13, 2015

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[1] See non-IFRS measurements section on page 5 of this MD&A

Bengal's producing assets are predominantly situated in Australia's Cooper Basin, a region featuring large hydrocarbon pools. The Company's core Australian assets, Cuisinier and Tookoonooka, are situated within an 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 favorable royalty regime for oil and gas production.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the three and six months ended September 30, 2015 and 2014. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from July 1, 2015 through September 30, 2015. The terms "prior year's quarter" and "2015 quarter" are used throughout the MD&A for comparative purposes and refer to the period from July 1, 2014 through September 30, 2014.

The fiscal year for the Company is the twelve-month period ended March 31, 2016. The terms "fiscal 2016," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2015 through March 31, 2016. The terms "previous year," "prior year" and "fiscal 2015" are used in the MD&A for comparative purposes and refer to the period from April 1, 2014 through March 31, 2015. The term YTD means year-to-date.

For the purpose of calculating unit costs, natural gas volumes have been converted to barrels of oil equivalent ("boe") using a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of oil. This conversion ratio of 6:1 is based on an energy equivalency conversion for the individual products, primarily at the burner tip, and is not intended to represent a value equivalency at the wellhead. Such disclosure of boe may be misleading, particularly if used in isolation.

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.

OUTLOOK

AUSTRALIA

ATP 752 Barta Block Cuisinier

The objective of the Joint Venture is to optimize production and cash flows through minimal capital expenditures as a response to the recent instability in benchmark commodity prices. During the quarter the Joint Venture has approved a five-well fracture stimulation program targeting select wells that have demonstrated significant oil pay zones but with low deliverability due to well-bore damage and reduced permeability. The total cost of this program, which is scheduled to commence in December, is estimated at $3.6 million (1.1 million net to the Company).

As a result of the continued geographical expansion and associated increase in estimated initial oil in place, the joint venture, led by the operator, has commenced the preparation of a field development plan set to optimize field recovery in a cost effective manner.

ATP 732 Tookoonooka Block

In Bengal's Tookoonooka Permit (ATP 732 - WI 50%), which is located in the emerging East Flank oil fairway of the Cooper Basin, the Company is partnered with Beach Energy Ltd. ("Beach"). Beach completed the acquisition of 300 sq. km 3D seismic in Tookoonooka in February 2014. Following the ongoing seismic interpretation, the joint venture is expected to identify at least one drilling location and commence exploration drilling. Bengal is carried by Beach in this next exploration well, which is not expected before Q1 of calendar 2016.

ATP 752 Wompi

The Nubba-1 well, which encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas pay is expected to be evaluated late 2015 or early 2016. 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 suggests the prospective gas pay extends down dip of the Nubba well where seismic indicates the Toolachee section thickens. With positive test results, a Petroleum Production Lease will be applied for which will allow for commercialization. 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 offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential.

ATP 934 Barrolka

Bengal has completed reprocessing of 500+ line kilometers of 2D seismic over the permit and interpretation of this data is underway. Once complete the most favorable areas will be high-graded for additional detailed geophysical work that may include the acquisition of 3D seismic in 2016.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Revenue						
Oil	**$ 3,392**	$ 4,380	(23)	**$ 7,096**	$ 8,166	(13)
Natural gas	**-**	71	(100)	**-**	160	(100)
Natural gas liquids	**-**	7	(100)	**-**	21	(100)
Total	**$ 3,392**	$ 4,458	(24)	**$ 7,096**	$ 8,347	(15)
Royalties	**$ 235**	$ 205	15	**$ 489**	$ 486	1
% of revenue	**6.9**	4.6	50	**6.9**	5.8	19
Operating & transportation	**$ 1,879**	$ 1,520	24	**$ 3,574**	$ 2,726	31
Operating netback[1]	**$ 1,278**	$ 2,733	(53)	**$ 3,033**	$ 5,135	(41)
Cash from operations:	**$ 2,318**	$ 2,232	4	**$ 2,967**	$ 4,451	(33)
Funds from operations:[2]	**$ 1,282**	$ 1,459	(12)	**$ 2,504**	$ 2,385	5
Per share ($) (basic & diluted)	**0.02**	0.02	-	**0.04**	0.04	-
Net income (loss)	**$ 1,167**	$ (98)	(1,291)	**$ (89)**	$ (827)	(89)
Per share ($) (basic & diluted)	**0.02**	0.00	-	**0.00**	(0.01)	(100)
Adjusted net (loss) income[3]	**$ (283)**	$ 115	(346)	**$ (462)**	$ (754)	(39)
Per share ($) (basic & diluted)	**(0.00)**	0.00	-	**(0.01)**	(0.01)	-
Capital expenditures	**$ 596**	$ 2,909	(80)	**$ 1,704**	$ 6,564	(74)
Volumes						
Oil (bopd)	**592**	428	38	**556**	377	48
(Natural gas (mcfpd)	**-**	169	(100)	**-**	181	(100)
Natural gas liquids (boepd)	**-**	1	(100)	**-**	1	(100)
Total (boepd @ 6:1)	**592**	457	30	**556**	408	36
Netback[1] ($/boe)						
Revenue	**$ 62.31**	$106.11	(41)	**$ 69.71**	$111.51	(38)
Realized gain on financial instruments	**13.50**	-	-	**11.48**	-	-
Royalties	**$ 4.32**	$ 4.88	(12)	**4.80**	6.49	(26)
Operating & transportation	**$ 34.52**	$ 36.18	(5)	**35.11**	36.42	(4)
Netback	**$ 36.97**	$ 65.05	(43)	**$ 41.28**	$ 68.60	(40)

(1) Operating netback is a non-IFRS measure. Netback per boe is calculated by dividing the revenue and less royalties, operating and transportation costs by the total production of the Company measured in boe.
(2) Funds from operations is a non-IFRS measure. The comparable IFRS measure is cash from operations. A reconciliation of the two measures can be found in the table on page 5.
(3) Adjusted net (loss) is a non-IFRS measure. The comparable IFRS measure is cash from operations. A reconciliation of the two measures can be found in the table on page 5.

Non-IFRS Measurements

Bengal uses measurements primarily based on IFRS as issued by the IASB and also certain secondary non-IFRS measurements commonly used in the oil and gas industry. The non-IFRS measurements included in this Management's Discussion and Analysis are funds from operations, funds from operations per share, adjusted net earnings, adjusted net earnings per share and operating netbacks which do not have any standardized meaning under IFRS and are referred to as non-IFRS measures.

Operating netbacks assist management and investors to evaluate the specific operating performance of the Company by product and is equal to total revenue less royalties and operating and transportation expenses calculated on a boe basis. Management utilizes these measures to analyze operating performance. Funds from operations is not intended to represent operating profit for the period nor should it be viewed as an alternative to operating profit, net income, cash from operations or other measures of financial performance calculated in accordance with IFRS. Total boe is calculated by multiplying the daily production by the number of days in the period.

Funds from operations is a non-IFRS measure, which should not be considered an alternative to “Net cash from operating activities” and is comprised of cash from operating activities as presented in the consolidated statement of cash flows adding changes in non-cash working capital and the settlement of decommissioning liabilities. Funds from operations, commonly referred to as cash flow by research analysts, is used to value and compare oil and gas companies and is frequently included in published research when providing investment recommendations and is presented in the Company’s’ financial reports to assist management and investors in analyzing the Company’s operating performance. Funds from operations per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income (loss) per share.

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

	Three Months Ended September 30			Six Months Ended September 30		
$000s	**2015**	2014	% Change	**2015**	2014	% Change
Cash flow from (used in) operating activities	**2,318**	2,232	4	**2,967**	4,451	(33)
Changes in non-cash working capital	**(1,036)**	(773)	34	**(463)**	(2,066)	(78)
Funds from (used in) operations	**1,282**	1,459	(12)	**2,504**	2,385	5

Adjusted net earnings is a non-IFRS measure, which should not be considered an alternative to “Net (loss) income” as presented in the consolidated statement of (loss) income and comprehensive (loss) income 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 (loss) income less unrealized losses/gains on foreign exchange and unrealized losses/gains on financial instruments. Adjusted net earnings per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net income (loss) per share.

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

	Three Months Ended September 30			Six Months Ended September 30		
$000s	**2015**	2014	% Change	**2015**	2014	% Change
Net income (loss)	**1,167**	(98)	(1,291)	**(89)**	(827)	(89)
Unrealized loss (gain) on financial Instruments	**(3,185)**	-	-	**(2,139)**	-	-
Unrealized foreign exchange loss	**1,735**	213	715	**1,766**	73	2,319
Adjusted net earnings (loss)	**(283)**	115	(346)	**(462)**	(754)	(39)

RESULTS OF OPERATIONS - AUSTRALIA

Netbacks

Production	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Oil Production (bpd)	**592**	428	38	**556**	377	48
($000s)						
Oil Sales	**3,392**	4,380	(23)	**7,096**	8,166	(13)
Realized loss (gain) on financial instruments	**735**	-	-	**1,169**	-	-
Royalties	**235**	194	21	**489**	463	6
Operating expenses	**1,872**	1,454	29	**3,565**	2,603	37
Netback ($000s)	**2,020**	2,732	26	**4,211**	5,100	(17)
Oil Sales ($/bbl)	**62.31**	111.34	(44)	**69.71**	118.23	(41)
Realized gain on financial instruments ($/bbl)	**13.50**	-	-	**11.48**	-	-
Royalties ($/bbl)	**4.32**	4.93	(12)	**4.80**	6.70	(28)
Operating expenses ($/bbl)	**34.38**	36.96	(7)	**35.02**	37.69	(7)
Netback ($/bbl)	**37.10**	69.45	(47)	**41.37**	73.84	(44)

Production, Commodity Pricing and Sales

Production

The 38% increase in production compared to Q2 2015 is due primarily to incremental production from the Cuisinier Phase One and Phase Two drilling programs as all six wells were on stream for the entire quarter producing approximately 310 bopd net to Bengal. These production gains were partially offset by natural production declines. Production increased by approximately 14% compared to the preceding quarter due to incremental production from the Cuisinier 20 and Cuisinier 21 wells which were on stream for the majority of the quarter adding approximately 130 bopd of incremental production net to Bengal.

Pricing

The price received for Bengal's Australian oil sales is benchmarked on Dated Brent quotes as published by Platts Crude Oil Marketwire for the month in which the Bill of Lading occurs, plus a Platts Tapis premium. Brent typically has traded at a premium to West Texas Intermediate (WTI) and the Platts Tapis premium received has averaged US $2.18/bbl over Brent for the six months ended September 30, 2015 (2014 – US $3.96).

Realized crude oil prices decreased by 44% and 20% compared to Q2 2015 and Q1 2016 respectively due to a corresponding fluctuations in benchmark pricing. Declines in Brent crude prices have been partially offset by foreign exchange gains as the value of Canadian and Australian dollars has decreased relative to U.S. dollars.

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

Prices and Marketing	Three Months Ended September 30			Six Months Ended September 30		
Average Benchmark Price	**2015**	2014	% Change	**2015**	2014	% Change
Bengal realized crude oil price before realized gain on financial instruments($CAD/bbl)	**$ 62.31**	$111.34	(44)	$ 69.71	$118.23	(41)
Realized gain on financial Instruments ($CAD/bbl)	**13.50**	-	-	11.48	-	-
Dated Brent oil ($CAD/bbl)	**65.67**	111.32	(41)	71.14	115.46	(38)
Dated Brent oil ($US/bbl)	**50.26**	101.85	(51)	56.09	105.74	(47)
Number of CAD$ for 1 AUS$	**0.95**	1.01	(6)	0.95	1.01	(6)
Number of CAD$ for 1 US$	**1.31**	1.09	20	1.27	1.09	17

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.

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.

The company has managed the price application to production volumes through the following contracts:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US$/bbl)	Price Ceiling (US$/bbl)
October 1, 2015 – May 31, 2017	Oil - Swap	107,748	80.00	80.00
October 1, 2015 – May 31, 2017	Oil – Put option	88,156	80.00	-

The fair value of the financial contracts outstanding as at September 30, 2015 is an estimated asset of $6.9 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 six months ended September 30, 2015, the derivative commodity contracts resulted in a realized gain of $1.2 million (2014 - $nil million) and an unrealized gain of $2.1 million (2014 - $nil million),

Royalties

Royalties ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Royalty Expense	**235**	194	21	**489**	463	6
$/boe	**4.32**	4.93	(12)	**4.80**	6.70	(28)
% of revenue	**7**	4	75	**7**	6	17

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 transportation and operating costs, resulting in an effective rate of less than 10%.

Royalties per barrel have decreased 12% compared to Q2 2014 and decreased 7% compared to the previous quarter. Royalties as a percentage of revenues are 7% for the current quarter compared to 4% during Q2 2015 during which the Company recognized royalty credits related to its Toparoa asset in Australia. Royalties are expected to fluctuate between 6-7% of revenues based on historical allowable operating costs deductions.

Operating & Transportation Expenses

Operating & trans. expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Operating	**311**	270	15	**624**	489	28
Transportation	**1,561**	1,184	32	**2,941**	2,114	39
	1,872	1,454	29	**3,565**	2,603	37
Operating - $/boe	**5.71**	6.86	(17)	**6.13**	7.08	(13)
Transp. - $/boe	**28.67**	30.10	(5)	**28.89**	30.61	(6)
	34.38	36.96	(7)	**35.02**	37.69	(7)

Operating costs per barrel decreased by 17% compared to Q2 2015 and decreased by 14% compared to the prior quarter. The decrease was the result of increased production relative to operating costs as well as the impact of foreign exchange as the value of the Australian dollar has depreciated relative to the Canadian dollar compared to both the prior year and prior quarter.

Transportation costs on a boe basis have decreased 5% compared to Q2 2015 and decreased 2% compared to the prior quarter. The decrease was due primarily to foreign exchange as the value of Australian dollars depreciated against Canadian dollars during the period.

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

G&A Expenses and SBC ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Net G&A	**650**	826	(21)	**1,324**	1,747	(24)
Capitalized G&A	**83**	83	-	**161**	206	(22)
Total G&A	**733**	909	(19)	**1,485**	1,953	(24)
Expensed share-based compensation	**24**	50	(52)	**48**	105	(54)
Capitalized share-based compensation	**3**	11	(73)	**7**	28	(75)
Total share-based compensation	**27**	61	(56)	**55**	133	(59)

The 19% decrease in total G&A expenditures compared to Q2 2015 and 3% decrease compared to the prior quarter reflects the Company’s ongoing effort to minimize discretionary spending without impacting operations, as well as the depreciation of the Australian dollar compared to the Canadian dollar.

Share based compensation

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of the grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire three to five years from the grant date; and vesting terms vary by grant with some vesting one-third on the grant date and one-third on each of the following two annual anniversaries and others vesting based on performance-based criteria established by the Company’s Board of Directors.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
PNG – Australia	**1,429**	1,194	20	**2,675**	2,084	28
PNG – Canada	**6**	19	(68)	**13**	40	(68)
Subtotal	**1,435**	1,213	18	**2,688**	2,124	27
Rig - Canada	**-**	165	(100)	**-**	165	(100)
Total	**1,435**	1,378	4	**2,688**	2,289	17
$/boe – PNG Australia	**26.25**	30.35	(14)	**26.28**	30.17	(13)
$/boe – PNG Canada	**-**	68.84	-	**-**	35.44	-
$/boe – Total PNG	**26.36**	32.80	(20)	**26.41**	30.58	(14)

Depletion per boe decreased in Australia compared to the prior year due to increases in total reserve volumes partially offset by an increase in expected future capital costs associated with those reserves.

Impairment

Impairment ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Total	**-**	69	(100)	**-**	796	(100)

There were no impairment charges recognized during the six months ended September 30, 2015.

Finance Income/Expenses

Finance Income/Expenses ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Interest income	**2**	4	(50)	**5**	9	(44)
Accretion expense on decommissioning liabilities	**(8)**	(4)	100	**(16)**	(7)	129
Accretion expense on notes payable	**-**	(53)	(100)	**-**	(106)	(100)
Change in FV of VARs	**12**	64	(81)	**(1)**	18	(106)
Letter of credit charges	**-**	-	-	**14**	-	-
Interest on notes payable and credit facility	**(326)**	(246)	33	**(630)**	(489)	29
Total	**(320)**	(235)	36	**(628)**	(575)	9

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

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
Geological and geophysical	**433**	488	(11)	**791**	547	45
Drilling	**(35)**	73	(148)	**(55)**	3,210	(102)
Completions	**197**	2,348	(92)	**857**	2,807	(70)
ATP 934 working interest purchase	**1**	-	-	**111**	-	-
Total oil & gas expenditures	**596**	2,909	(80)	**1,704**	6,564	(74)
Office	**-**	-	-	**-**	-	-
Total	**596**	2,909	(80)	**1,704**	6,564	(74)
Exploration & evaluation expenditures	**225**	218	3	**492**	944	(48)
Development & production expenditures	**371**	2,691	(86)	**1,212**	5,620	(78)
Total	**596**	2,909	(80)	**1,704**	6,564	(74)

Development expenditures during the quarter related primarily to the tie-in of the Cuisinier Phase Two drilling campaign and exploration and evaluation expenditures relate primarily to administrative costs associated with the interpretation and review of seismic data.

SHARE CAPITAL

At November 13, 2015, there were 68,177,796 common shares issued and outstanding, together with 4,357,500 outstanding options, 703,125 warrants and 546,875 VARs. During the quarter, the Company issued 1,072,500 stock options at a price of $0.18/share.

Trading History	Three Months Ended September 30			Six Months Ended September 30		
	2015	2014	% Change	**2015**	2014	% Change
High	**$ 0.26**	$ 0.62	(58)	**$0.32**	$ 0.76	(58)
Low	**$ 0.14**	$ 0.40	(65)	**$0.14**	$ 0.40	(65)
Close	**$ 0.15**	$ 0.45	(67)	**$0.15**	$ 0.45	(67)
Volume (000s)	**652**	2,281	(71)	**5,805**	7,753	(25)
Shares outstanding (000s)	**68,178**	64,692	5	**68,178**	64,692	5
Weighted average shares outstanding (000s)						
Basic	**68,178**	64,692	5	**68,178**	64,688	5
Diluted	**68,220**	64,692	5	**68,178**	64,688	5

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. The Company's existing cash and cash equivalents and operating cash flows combined with the available credit described above are expected to be sufficient to meet all of its working capital requirements for at least the next twelve months and its commitments under its capital program (see Commitments below).

At September 30, 2015 the Company had $5.8 million of working capital, including cash and short-term deposits of $2.3 million and restricted cash of $0.1 million, compared to working capital of $3.1 million, at June 30, 2015 and a working capital deficiency of $1.7 million at September 30, 2014.

In the previous fiscal year, Bengal had finalized a US $25.0 million secured credit facility drawing US $14.0 million in November and subsequently redeeming its $8.0 million notes payable. Proceeds from this facility are restricted for use within the Cuisinier production license.

The majority of the Company's oil sales are benchmarked on dated Brent prices which averaged US $56.09/bbl for the six months ended September 30, 2015. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. To mitigate the net impact of low crude prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside. The Company has also entered into derivative commodity contracts to reduce the impact of price volatility.

Bengal will continue to monitor trends in commodity prices to ensure its financial obligations are met, while continuing to grow its asset base where appropriate.

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

Credit facility (US$000s)	
Fiscal year 2017	7,750
Fiscal year 2018	6,250
	14,000

COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities in its Indian permits 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 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 will vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore India – CY-ONN-2005/1	3 wells	Currently under Force Majeure	$5.6

(1) Translated at September 30, 2015 at an exchange rate of US $1.00 = CAD $1.3409.
(1) If the Company did not participate in the drilling of 3 wells, costs of $5.3 million would be impaired and the Company's interest in the permit would decline.

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. Currently the Company holds a 71.43% operating interest in this permit. Work program consists of 500 kilometers of 2D seismic and up to three wells.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 934P	500 km^2 of 2D seismic and up to three wells	6 years after grant of ATP	$ 15.5

(1) Translated at September 30, 2015 at an exchange rate of AUS $1.00 = CAD $0.9355.

GUARANTEES – INDIA PERMITS

($000s) CAD	September 30, 2015	September 30, 2014
CY-OSN-2005/1 – Onshore India	**969**	806
Total Guarantees	**969**	806

These performance guarantees are based on a percentage of the capital commitments shown in the table above and are not reflected in the statement of financial position, as they are secured by Export Development Canada. These guarantees are cancelled when the Company completes the work program commitment required for the applicable exploration period.

OTHER

At September 30, 2015, 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	398	265	133	-	-
Decommissioning obligations	1,420	-	57	169	1,194
Total contractual obligations	1,818	265	190	169	1,194

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

($000s, except per share amounts)

	Sep. 30 2015	Jun. 30 2015	Mar. 31 2015	Dec. 31 2014	Sep. 30 2014	Jun. 30 2014	Mar. 31 2014	Dec. 31 2013
Petroleum and natural gas sales	**$3,392**	$3,704	$3,378	$3,944	$4,458	$3,889	$5,272	$5,516
Cash from (used in) operations	**2,318**	649	1,031	1,144	2,232	2,219	2,106	2,170
Funds from (used in) operations(1)	**1,282**	1,222	939	1,318	1,459	926	2,218	2,862
Per share								
Basic and diluted	**0.02**	0.02	0.01	0.02	0.02	0.01	0.03	0.04
Net income (loss)	**$1,167**	$(1,256)	$(1,052)	$(1,293)	($98)	($729)	($1,804)	$573
Per share								
Basic and diluted	**0.02**	(0.02)	(0.02)	(0.02)	0.00	(0.01)	(0.03)	0.01
Capital expenditures	**$596**	$1,108	$2,410	$4,489	$2,909	$3,655	$2,048	$6,462
Working capital (deficiency)	**5,775**	3,087	5,221	4,931	(1,705)	(88)	3,104	3,590
Total assets	**66,583**	62,926	65,679	66,229	60,385	60,216	62,425	61,353
Shares outstanding (000s)	**68,178**	68,178	68,178	64,692	64,692	64,692	64,446	64,315
Operations								
Average daily production								
Natural gas (mcfpd)	**-**	-	114	181	169	194	180	184
Oil and NGLs (bpd)	**592**	520	506	548	429	329	474	465
Combined (boepd)	**592**	520	525	578	457	361	504	496
Netback ($/boe)	**36.97**	46.23	45.86	$36.79	$65.05	$73.15	$74.28	$83.13

(1) See “Non-IFRS Measurements” on page 5 of this MD&A.

Production over the last eight quarters initially climbed with the addition of 2014 Phase One wells during fiscal Q3 2015 after which production declined naturally offset partially during Q1 2016 as 2014 Phase Two wells were brought on stream near the end of the quarter after which production has increased to 592 bopd during Q2 2016.

The decrease in netbacks from the fiscal fourth quarter of 2015 through to Q2 2016 are due primarily to decreased benchmark crude prices and pipeline costs which are marginally higher than costs incurred previously to truck oil. However, this ensures continuous deliverability.

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at December 31, 2014 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;
- 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, which are reviewed on an ongoing basis. A full discussion of the Company's critical judgments and accounting estimates is included in its 2015 annual Management's Discussion and Analysis.

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.

Accounting for acquisitions of interests in joint operations

In May 2014, the IASB issued amendments to IFRS 11 "Joint Arrangements" to clarify that the acquirer of an interest in a joint operation in which the activity constitutes a business is required to apply all of the principles of business combinations accounting in IFRS 3 "Business Combinations". Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it increases or decreases its ownership share in an existing joint operation or invests in a new joint operation.

Sale or contribution of assets between an investor and its associate or joint venture

In September 2014, the IASB issued amendments to address an inconsistency between the requirements in IFRS 10 "Consolidated Financial Statements" and those in IAS 28 "Investments in Associates and Joint Ventures" regarding the sale or contribution of assets between an investor and its associate or joint venture. The amendment clarified that a full gain or loss is recognized when a transaction involves a business. A partial gain or loss is recognized when a transaction involves assets that do not constitute a business. Prospective application of this interpretation is effective for annual periods beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amendment could impact the Company in the event that it has transactions with associates or joint ventures.

Disclosure initiative

In December 2014, the IASB issued narrow-focus amendments to IAS 1 "Presentation of Financial Statements" to clarify existing requirements relating to materiality, order of notes, subtotals, accounting policies and disaggregation. Retrospective application of this standard is effective for fiscal years beginning on or after January 1, 2016, with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the Company's disclosure.

Revenue from contracts with customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers". It replaces existing revenue recognition guidance and provides a single, principles-based five-step model to be applied to all contracts with customers. Retrospective application of this standard was to be effective for fiscal years beginning on or after January 1, 2017, with earlier application permitted. On May 19, 2015, the IASB published the expected exposure draft aimed at deferring the effective date of IFRS 15 "Revenue from Contracts with Customers" to January 1, 2018. On July 22, 2015, the IASB confirmed its proposal to defer the effective date to January 1, 2018. The Company is currently assessing the impact of this standard.

Financial instruments: recognition and measurement

In July 2014, IFRS 9 "Financial Instruments" was issued as a complete standard, including the requirements previously issued related to classification and measurement of financial assets and liabilities, and additional amendments to introduce a new expected loss impairment model for financial assets including credit losses. Retrospective application of this standard with certain exemptions is effective for fiscal years beginning on or after January 1, 2018, with earlier application permitted. The Company is currently assessing the impact of this standard.

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated June 29, 2015 filed on SEDAR at www.sedar.com.

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

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 1810, 801 6th Avenue SW., Calgary, Alberta T2P 3W2, 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;*
- *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 $35/bbl under current market conditions;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Expectation that the selection of three drilling locations in India expected to commence no earlier than late calendar 2015.*
- *That Beach Energy will perform the work agreed to under the Farm-out and that further drilling activities on ATP 732P will occur in 2016;*

.

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
Johnson Winter Slattery • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Computershare • Toronto, Canada

INVESTOR RELATIONS

5 Quarters Investor Relations, Inc. • Calgary, 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

All Directors are members of the Committee

AUDIT COMMITTEE

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

RESERVES COMMITTEE

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

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
Jerrad Blanchard, Chief Financial Officer
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG