International exploration & production

Management's Discussion & Analysis

Three and Nine Months Ended December 31, 2012 and 2011

HIGHLIGHTS

During the period the Company experienced the following significant highlights and events:

- **Cuisinier - Combined oil production exceeds initial estimates:** Combined oil exit December 2012 producing day production rate was 1,315 barrels of oil per day (net 328) from 5 of the 8 wells in the field. Production from all wells is expected to commence early in April of 2013 when pipeline connection and production infrastructure is complete and a long term field production license is received. Benefits of the pipeline are expected to include; reduced production downtime, higher sustained production levels, improved operational flexibility and an overall reduction in operating and transportation costs of approximately $5 to $7 per barrel.

- **Cuisinier Drilling and Seismic:** Five firm and one contingent appraisal wells are now planned to commence drilling in March of 2013. A new 224 square kilometre 3D seismic survey has been completed with processing and interpretation expected mid-year. Further appraisal and exploration drilling will occur in 2014.

- **A Cuisinier reserves update (net to Bengal) completed in September by GLJ Petroleum Consultants Ltd.** recognized 717,000 proved barrels (an increase of 904%), 1,550,000 proved plus probable barrels (an increase of 269%) and 7,512,000 proved plus probable plus possible barrels (an increase of 614%) net to Bengal (at its 25% working interest). The net present values discounted at 10% amount to $16 million for proved, $37 million for proved plus probable and $164 million for proved plus probable plus possible. (Note 1 and 2)

- **100% Working Interest New Oil Discovery at the Caracal #1 well on the Tookoonooka Property:** Drilling and Testing operations indicate a new oil discovery of 52° API gravity oil from the Wyandra Formation. A fracture stimulation and appraisal drilling program on the Caracal structure is being planned and geophysical review is continuing.

- **Onshore Cauvery Seismic:** Acquisition and processing of 575 square kilometers of 3D seismic data are now complete. Interpretation of the data is currently in progress with a 3 well drilling program scheduled to commence in calendar Q3 2013. Bengal has a 30% working interest in this block.

- **Cashflow to increase significantly in 2013:** Funds flow from operations (this is a non-IFRS measure – see footnote 2 from the table on page 6) for the three months ended December 31, 2012 improved to $481,000 compared to negative $402,000 in the prior year three month period. The Company expects cash generation to increase over the year as production from Cuisinier ramps up with the completion of the tie in to the Cook facility. By year end 2013 the Company should be producing sufficient cash flow to fund ongoing exploration. However, some external financing will be required to meet partner drilling commitments in 2013. Management's view is that the current stock price does not adequately reflect the value of the Company's assets and future prospects and Management is therefore reluctant to issue common shares at a price that would see dilution of the existing shareholders' interest. Management is pursuing a number of alternatives simultaneously that could provide necessary capital while, at the same time, maintaining or enhancing the underlying per share value. These initiatives include structured finance instruments, farm out discussions, joint venture partnerships and the potential divestiture of some non-core assets.

- **Bengal Reports Financial Results for the three and nine months ended December 31, 2012:** The Company reported that revenues in the three and the nine months ended December 31, 2012 amounted to $1,937,000 and $2,872,000, respectively compared to $1,328,000 and $3,664,000 respectively in 2011. The net loss for the three and nine months ended December 31, 2012 amounted to $151,000 or $0.00 per share and $1,207,000 or $0.02 per share respectively, compared to the net loss for the three and nine months ended December 31, 2011 of $477,000 or $0.01 per share and $5,785,000 or $0.11 per share, respectively. The Company spent $9,475,000 in the three months ended December 31, 2012 and $27,100,000 in the nine months ended December 31, 2012 related to the drilling of four Cuisinier wells, the acquisition of the drilling rig, seismic acquisition in Australia and India and drilling the Caracal-1 well.

- Notes:

- (1) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

- (2) It should not be assumed that the future net revenues presented in this press release represent the fair market value of the reserves

MANAGEMENT'S DISCUSSION AND ANALYSIS – FEBRUARY 12, 2012

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the unaudited Condensed Consolidated Interim Financial Statements and accompanying notes for the three and nine months ended December 31, 2012 and 2011 and the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2012 and 2011. Bengal's financial statements were prepared under International Financial Reporting Standards ("IFRS"). Additional information relating to the Company, including detailed reserve disclosures, is included in the Company's Annual Information Form, which is available on SEDAR at www.sedar.com. The reader should be aware that historical results are not necessarily indicative of future performance.

Bengal's activities are focused in Australia, India and Canada. Over the reporting period, revenue and expenses were generated and capital expenditures were made in Australia and Canada, and capital expenditures were made in India. The Company's activities are carried out primarily in Canadian dollars as well as the currencies of each country in which the Company operates. The Company reports financial results in Canadian dollars.

OUTLOOK

AUSTRALIA – Onshore

Authority to Prospect ("ATP") 752 Barta Block - Cuisinier

The Company has participated at its 25% working interest in a total of eight successful Murta Formation oil wells (8 oil wells out of 8 drilled). These eight wells are expected to be on sustained production by April of 2013 through a pipeline currently under construction connecting the Cuisinier production to the Cook Oilfield production infrastructure. Continued production is dependent upon receipt of a Production License which has been submitted to the Minister and approval is expected in the next few months. A further 5 firm and one contingent appraisal wells are planned for 2013 commencing in March. An exploratory drilling campaign is anticipated in 2014 to test anomalies defined by the recently completed 224 square kilometer Cuisinier North 3D seismic program.

Current production is being trucked to market and exit December 31, 2012 producing day volumes were 1,315 barrels of oil per day (net 328). Cuisinier oil is sold at Brent pricing plus a premium for quality. Average sale price of the Cuisinier oil for the three months ending December 31, 2012 was $112.30 CAD per barrel and average field netbacks after royalty and operating and transportation costs were $66.26 CAD per barrel.

Cuisinier, with a reserves update completed by GLJ Petroleum Consultants in September of 2012 (the results of this reserves update were contained in an October 5, 2012 press release), has been assigned 7.5 million Proved plus Probable plus Possible ("3P") barrels of oil to the Company's interest in the Cuisinier property, a 614% increase from March 31, 2012. Proved reserves increased to 0.7 million barrels, a 904% increase from March 31, 2012, while Proved plus Probable ("2P") reserves increased to 1.5 million barrels, a 269% increase.

ATP 732 Tookoonooka Block

Utilizing the recently acquired and 100%-owned drilling rig ("Bengal 1" or the "Rig"), drilling operations on the first of three initial exploratory wells on the Tookoonooka Block commenced in October. The Bengal Caracal-1 exploration well was spud on October 5, 2012 and was announced as a new discovery of 52 degree API gravity oil by the Company's Press Release dated November 5, 2012.

Currently a fracture stimulation and appraisal drilling program is being planned for the Caracal project, in parallel, a detailed review of existing 3D seismic data on this block is being carried out. Drilling operations will commence once a partner for this permit is found.

The two remaining exploration drill locations selected for the drilling campaign are targeting Cretaceous and Jurassic oil as well as Permian gas. All three locations have been chosen based on their multi-zone potential with as many as three or four prospective targets on each location.

The Company holds a 100% working interest in ATP 732 and is actively seeking farm-in partners for future participation in the block.

ATP 934 Barrolka Block

Final application for grant of the permit at ATP 934 (Barrolka Block) has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the Ministerial Grant of the tenement is received. The Company holds a 50% operating interest in this 361,268 acre permit.

Australia - Offshore

AC/P 47 Block

On October 19, 2012 Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA). If a joint venture partner is found, the Company will then shoot, process and interpret a minimum of 750 square km of 3D seismic on this permit during Q1 2013. The results of this seismic program will give Bengal the option of either committing to drill an exploration well or, if no acceptable prospects are identified from the seismic interpretation, relinquishing the permit. If the permit is relinquished, $0.8 million of historical exploration and evaluation costs plus the Company's share of any seismic program costs will be impaired.

India - Onshore

CY-ONN-2005/1 Block

On Bengal's 30% working interest, 233,000 gross acre Block CY-ONN-2005/1 located in the onshore Cauvery Basin, Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, completed the acquisition of approximately 575 square km of 3D seismic in October. Seismic data processing has been completed with preliminary interpretation now underway.

As well, airborne magnetometry work was carried out over the permit in association with the seismic program. These geophysical data sets will allow the joint venture to define drilling locations on the permit early in 2013 with three wells planned. These wells will target Cretaceous reservoirs known to produce from pools offsetting the permit to the north and west. Target depths will be between 1000m and 2500m.

India - Offshore

CY-OSN-2009/1 Block

Evaluation work is continuing on this 340,000 acre, 100% owned and operated Block CY-OSN-2009/1 in India's offshore Cauvery basin. Activity includes acquiring 2D and 3D surveys previously recorded on the block and in this region and reprocessing of certain available seismic records. Interpretation of the various seismic data sets has been completed with several play types and prospects emerging. This has now allowed planning to progress on a new seismic data program, with the acquisition of additional seismic data planned for 2013.

Recent competitor activity in the local area, including the $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance and the recently announced exploration discoveries by Cairn India in nearby Sri Lankan waters provide encouragement for acceleration of the Bengal activity. Preliminary work suggests that the prospects identified on the Company permit occur in a geological section and with a prospect style similar to that of the Cairn discoveries.

If the Company is unable to make future work commitment payments on this permit, $0.8 million associated with this permit will be impaired.

The Company is actively seeking farm-in partners on this block.

Canada

On December 3, 2012 the Company's non-operated gas wells at Oak, British Columbia recommenced production.

SUMMARY

The Company has an attractive portfolio of both lower-risk and high-impact drilling opportunities. Increasing production from new wells at Cuisinier on the Barta permit should drive operating income for the Company and set the stage for future development. Potential near-term appraisal drilling and completion activity on the Caracal well and exploration drilling success on permit ATP 732P could create further momentum. Longer term plays in India are designed to potentially add value in 2013 and onward. The Company will continue to evaluate accretive production acquisition, exploration and corporate transaction opportunities, as and where they arise, within and around the Company's core areas.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended December 31			Nine Months Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Revenue						
Oil	**1,901**	1,213	57	**2,721**	3,361	(19)
Natural gas	**$ 35**	$ 92	(62)	**$ 105**	$ 250	(58)
Natural gas liquids	**1**	23	(96)	**46**	53	(13)
Total	**1,937**	1,328	46	**2,872**	3,664	(22)
Royalties	**172**	121	42	**255**	337	(24)
% of revenue	**8.9**	9.1	(2)	**8.9**	9.2	(3)
Operating & transportation	**623**	486	28	**1,032**	1,324	(22)
Netback(1)	**1,142**	721	58	**1,585**	2,003	(21)
Cash from (used in) operations:	**(378)**	(417)	(9)	**(822)**	(1,628)	(50)
Per share ($) (basic & diluted)	**(0.01)**	(0.01)	-	**(0.02)**	(0.03)	(33)
Funds from (used in) operations:(2)	**481**	(402)	NA	**(52)**	(824)	(94)
Per share ($) (basic & diluted)	**0.01**	(0.01)	NA	**0.00**	(0.02)	(100)
Net (loss):	**(151)**	(477)	(68)	**(1,207)**	(5,785)	(79)
Per share ($) (basic & diluted)	**(0.00)**	(0.01)	-	**(0.02)**	(0.11)	(82)
Capital expenditures	**$ 9,475**	$ 4,265	122	**$ 27,100**	$ 8,605	215
Volumes						
Natural gas (mcf/d)	**110**	271	(59)	**165**	238	(31)
Natural gas liquids (boe/d)	**1**	4	(75)	**3**	3	-
Oil (bbl/d)	**184**	108	70	**89**	103	(14)
Total (boe/d @ 6:1)	**203**	157	29	**119**	146	(19)
Netback(1) ($/boe)						
Revenue	**$ 103.33**	$ 92.03	12	**$ 87.84**	$ 91.50	(4)
Royalties	**9.18**	8.43	9	**7.80**	8.42	(7)
Operating & transportation	**33.23**	33.71	(1)	**31.56**	33.07	(5)
Total	**$ 60.92**	$ 49.89	22	**$ 48.48**	$ 50.01	(3)

(1) Netback is a non-IFRS measure. Netback per boe is calculated by dividing the revenue and costs in total for the Company 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 7.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the three and nine months ended December 31, 2012. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from October 1, 2012 through December 31, 2012. The terms "prior year's quarter" and "2011 quarter" are used throughout the MD&A for comparative purposes and refer to the period from October 1, 2011 through December 31, 2011.

The fiscal year for the Company is the 12-month period ended March 31, 2013. The terms “fiscal 2013,” “current year” and “the year” are used in the MD&A and in all cases refer to the period from April 1, 2012 through March 31, 2013. The terms “previous year,” “prior year” and “fiscal 2012” are used in the MD&A for comparative purposes and refer to the period from April 1, 2011 through March 31, 2012. 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: boe/d means barrels of oil equivalent per day; bbl/d means barrels per day; mcf/d 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. Funds from operations, funds from operations per share and netbacks do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Funds from operations represents cash from operating activities as presented in the consolidated statement of cash flows and adding back changes in non-cash working capital and the settlement of decommissioning liabilities. 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. Netbacks equal 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. 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. Total boe is calculated by multiplying the daily production by the number of days in the period.

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

	Three Months Ended December 31		**Nine Months Ended December 31**	
$000s	**2012**	2011	**2012**	2011
Cash flow used in operating activities	**(378)**	(417)	**(822)**	(1,628)
Changes in non-cash working capital	**859**	15	**770**	804
Funds from (used in) operations	**481**	(402)	**(52)**	(824)

RESULTS OF OPERATONS

Production

The following table outlines Bengal’s production volumes for the periods indicated:

Production	**Three Months Ended December 31**			**Nine Months Ended December 31**		
	2012	2011	% Change	**2012**	2011	% change
Natural gas (mcf/d)	**110**	271	(59)	**165**	238	(31)
NGLs (boe/d)	**1**	4	(75)	**3**	3	-
Oil (bbls/d)	**184**	108	70	**89**	103	(14)
Total (boe/d)	**203**	157	29	**119**	146	(19)

(1) Natural gas and NGL volumes are from the Company’s Oak property in Canada

(2) Oil volumes are from the Company's Cooper Basin permits in Australia

Oil production background:

- For the three and nine months ended December 31, 2011: oil production was mainly from Cuisinier 1, 2 and 3 (C1, C2 and C3).
- C1 was shut in January 2012 and C2 and C3 were shut in during August and September of 2012 due to the expiry of their Extended Production Test licenses (EPT).
- Cuisinier 4, 5, 6 and Cuisinier North 1 and Barta North 1 all commenced production in late October 2012 (C4, C5, C6, CN1 and BN1). The first four of these wells were drilled in the current year (the "Current Year wells") and are producing under an EPT for a six month period. If a long term production license, referred to below, is not obtained, these wells may be shut in after the six month EPT. There has been occasions where EPT licence extensions have been granted in the past.

Oil production increased to 203 b/d in the current quarter compared to 157 b/d in the prior year quarter due to commencement of production from the Current Year wells, partially offset by shut in of the C1, C2 and C3. The Company is awaiting regulatory approval of a Long-Term Petroleum Production License which is expected early in the second quarter of calendar 2013 which will allow continuous production from all wells.

Oil production declined to 119 b/d in the nine months ended December 31, 2012 compared to 146 b/d in the prior year period as C1, C2 and C3 produced for most of the prior year period whereas the Current Year wells only commenced production in late October 2012.

The decline in the Company's Oak B.C. non-operated gas production for the three and nine months ended December 31, 2012 is due to natural reservoir declines and shut in of the wells on September 1, 2012, due to low gas prices. The wells recommenced production on December 3, 2012.

Pricing

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

Prices and Marketing	**Three Months Ended December 31**			**Nine Months Ended December 31**		
	2012	2011	% Change	**2012**	2011	% Change
Average Benchmark Prices						
AECO 30 day firm ($/mcf)	**$ 3.05**	$ 3.47	(12)	**$ 2.36**	$ 3.64	(35)
Dated Brent oil ($US/bbl)	**110.11**	108.90	1	**109.34**	112.32	(3)
Number of CAD$ for 1 AUD$	**1.03**	1.04	(1)	**1.03**	1.03	-
Number of CAD$ for 1 USD$	**1.00**	1.02	(2)	**1.00**	0.99	1
WTI oil ($US/bbl)	**$ 88.87**	$ 97.43	(9)	**$ 91.06**	$ 96.35	(6)
Bengal's Realized Price ($CAD)						
Natural gas ($/mcf)	**$ 3.47**	$ 3.68	(6)	**$ 2.32**	$ 3.83	(39)
NGLs ($/bbl)	**8.00**	60.45	(87)	**59.51**	60.50	(2)
Oil ($/bbl)	**112.22**	122.62	(9)	**111.60**	118.88	(6)
Total ($/boe)	**$103.33**	$ 92.03	12	**$ 87.84**	$ 91.50	(4)

Bengal's total realized price on a boe basis for the nine months ended December 31, 2012, decreased as a result of both lower oil and gas prices.

Although realized product prices on a boe basis for the three months ended December 31, 2012 decreased, the total Company realized price on a boe basis increased due to product mix differences (higher gas volumes and lower oil volumes in the prior period).

The price received for Bengal's Australian oil sales is based 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 USD $5.11/bbl over Brent for the nine months ended December 31, 2012.

Oak, British Columbia gas sales are marketed by the operator and the price received is based on the reference price at British Columbia's Station 2 plus $0.03 per mcf. This has resulted in a realized price to the Company of $2.32/mcf and 3.47/mcf over the last nine and three months respectively.

NGLs include condensate, pentane, butane and propane. While prices for condensate and pentane have a relatively strong correlation to oil prices, prices for butane and propane trade at varying discounts due to the market conditions of local supply and demand.

Petroleum and Natural Gas Sales

The following table outlines Bengal's production sales by category for the periods indicated below:

Petroleum and Natural Gas Sales ($000s)		**Three Months Ended December 31**					**Nine Months Ended December 31**			
		2012		2011	% Change		**2012**		2011	% Change
Oil		**1,901**		1,213	57		**2,721**		3,361	(19)
Natural gas	**$**	**35**	$	92	(62)	**$**	**105**	$	250	(58)
NGLs		**1**		23	(96)		**46**		53	(13)
Total	**$**	**1,937**	$	1,328	46	**$**	**2,872**	$	3,664	(22)

(1) Natural gas and NGL sales are from the Company's Oak property in Canada

(2) Oil sales are from the Company's Cooper Basin permits in Australia

Petroleum and natural gas sales increased by $609,000 in the current quarter to $1,937,000 compared to $1,328,000 in the prior year quarter due to increased oil production volumes partially offset by lower oil prices.

YTD revenues declined from the prior year period due to lower oil volumes and prices.

Royalties

Royalties by Type ($000s)		**Three Months Ended December 31**					**Nine Months Ended December 31**			
		2012		2011	% Change		**2012**		2011	% Change
Canada Crown	**$**	**-**	$	6	(100)	**$**	**3**	$	18	(83)
Can. gross overriding		**1**		8	(88)		**7**		17	(59)
Australia		**171**		107	60		**245**		302	(19)
Total	**$**	**172**	$	121	42	**$**	**255**	$	337	(24)
$/boe		**9.18**		8.51	8		**7.80**		8.45	(8)
% of revenue		**8.9**		9.1	(2)		**8.9**		9.2	(3)
Royalties by Commodity		**Three Months Ended December 31**					**Nine Months Ended December 31**			
		2012		2011	% Change		**2012**		2011	% Change
Natural gas										
$000s	**$**	**-**	$	10	(100)	**$**	**1**	$	24	(96)
$/mcf		**-**		0.41	(100)		**0.02**		0.36	(94)
% of revenue		**-**		11.2	(100)		**1.0**		9.5	(90)
Oil										
$000s	**$**	**171**	$	107	60	**$**	**245**	$	302	(19)
$/bbl		**10.09**		10.85	(7)		**10.05**		10.70	(6)
% of revenue		**9.0**		8.9	1		**9.0**		9.0	-
NGLs										
$000s	**$**	**1**	$	4	(75)	**$**	**9**	$	11	(18)
$/bbl		**8.22**		15.84	(48)		**11.81**		15.00	(21)
% of revenue		**-**		17.0	488		**19.6**		21.0	(7)

Royalty payments are made by oil and natural gas producers to the owners of the mineral rights on the leases. These owners include governments (Crown) and freehold landowners as well as other third parties that may receive contractual overriding royalties.

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%.

In British Columbia, royalties are calculated based on average daily production from a well multiplied by a reference price. Bengal also pays a gross overriding royalty ("GORR") to the landholder of between 7.5% and 10% on some of its Oak gas wells.

Royalties have increased in the current quarter compared to the prior year quarter both on a total dollar and on a boe basis due to increased revenues and a larger proportion of higher royalty rate oil sales in the overall sales mix.

YTD royalties have decreased both on a total dollar and on a boe basis due to decreased revenue, prices and lesser proportion of higher royalty rate oil sales in the overall sales mix.

Operating & Transportation Expenses

Operating Expenses ($000s)						**Three Months Ended December 31**						**Nine Months Ended December 31**
		2012		2011	% Change			**2012**		2011	% Change	
Australia												
Operating	**$**	**291**	$	222	31		**$**	**424**	$	570	(26)	
Transportation		**318**		177	80			**465**		501	(7)	
		609		399	53			**889**		1,071	(17)	
Canada – Oper. costs		**14**		87	(84)			**143**		253	(44)	
Total	**$**	**623**	$	486	28		**$**	**1,032**	$	1,324	(22)	
Australia												
Operating - $/boe		**17.18**		22.41	(23)			**17.39**		20.16	(14)	
Transp. - $/boe		**18.77**		17.93	5			**19.07**		17.71	8	
Canada - $/boe		**7.75**		19.24	(60)			**17.20**		21.53	(20)	
Total ($boe)	**$**	**33.23**	$	33.71	(1)		**$**	**31.56**	$	33.07	(5)	

Operating and transportation expenses increased in the current quarter compared to the prior year quarter mainly as a result of increased oil volumes. Australian operating costs on a boe basis decreased as fixed operating costs declined per bbl as production volumes increased. Canadian operating costs declined due to lower gas volumes and also declined on a per boe basis as at September 30, 2012 a provision had been made for additional costs related to shut-in of production which were in excess of the actual costs incurred.

The decrease in YTD costs is primarily due to decreased sales volumes.

Transportation costs in Australia are incurred to transport Bengal's oil production through pipelines from various processing facilities to the centralized Moomba facility which accepts production from throughout the Cooper Basin in Australia. The oil is then sent through a pipeline to Port Bonython, South Australia.

General and Administrative (G&A) Expenses

General and Admin. Expenses ($000s)					**Three Months Ended December 31**				**Nine Months Ended December 31**
		2012		2011	% Change		**2012**	2011	% Change
G&A	**$**	**811**	$	853	(5)	**$**	**3,007**	$ 2,641	14
Capitalized G&A		**(146)**		-	-		**(384)**	-	-
Net G&A	**$**	**665**	$	853	(22)	**$**	**2,623**	$ 2,641	(1)

For the quarter, gross G&A expenses decreased $42,000 or 5% to $811,000 compared to $853,000 in the 2011 quarter. The decrease is due to recruiting and IFRS transition costs reflected in the prior year quarter, partially offset by higher rents in the current quarter as the Company moved on April 1, 2012 from lower cost sub-let space to new space due to the expiry of the sub-lease.

YTD gross G&A has increased $366,000 or 14% from the prior YTD period. The increase is due to higher rent and increased salaries from hiring a Vice President, Engineering and Operations, a Senior Geologist and a Senior Geophysicist part way through the prior YTD period.

Beginning the second quarter, the Company initiated capitalizing G&A expenses related to geological, geophysical and engineering expenses associated with exploration and development activities concurrent with the Company being operator for the first time and similar expenses associated with its newly acquired drilling rig.

Share-based Compensation (SBC)

Share-Based Compensation ($000s)				Three Months Ended December 31				Nine Months Ended December 31
		2012		2011	% Change	**2012**		2011	% Change
SBC – options	**$**	**144**	$	169	(15)	**$ 514**	$	686	(25)
SBC – capitalized		**(37)**		–	-	**(154)**		-	-
Share-based compensation	**$**	**107**	$	169	(37)	**$ 360**	$	686	(48)

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 increase to contributed surplus. Options expire three to 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. Effective with the option grant on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries.

Capitalized share-based compensation is based on the portion of capitalized fees to total fees paid to consultants and employees that have been granted options.

In the current quarter 1,150,000 stock options were granted, 375,000 expired and 136,667 were forfeited. No options were exercised during the period. The decrease in share-based compensation, before capitalization, from $686,000 to $514,000 YTD and $169,000 to $144,000 in the current quarter is a result of having 1,150,000 options granted in the nine months ended December 31, 2011 with one third vesting immediately and therefore having one third of their fair value expensed immediately, whereas for the 1,150,000 options granted in the current quarter, the first one third vest after one year.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)				Three Months Ended December 31				Nine Months Ended December 31
		2012		2011	% Change		**2012**		2011	% Change
PNG – Australia	**$**	**423**	$	91	365	**$**	**547**	$	229	139
PNG – Canada		**25**		35	(29)		**90**		98	(8)
Subtotal		**448**		126	256		**637**		327	95
Rig - Canada		**73**		-	-		**73**		-	-
Total	**$**	**521**	$	126	314	**$**	**710**	$	327	117
$/boe – PNG Australia		**24.97**		9.18	172		**22.43**		8.09	177
$/boe – PNG Canada		**13.84**		7.71	80		**10.82**		8.32	30
$/boe – Total PNG	**$**	**23.90**	$	8.72	174	**$**	**19.48**	$	8.16	139

Depletion per boe increased in Australia due to the increase in future capital costs related to the proved undeveloped and probable reserves at December 31, 2012.

Impairment

Impairment ($000s)					Three Months Ended December 31					Nine Months Ended December 31
		2012		2011	**% Change**		**2012**		2011	% Change
	$	**10**	**$**	(251)	NA	**$**	**(748)**	$	4,089	(118)

In the nine months ended December 31, 2012 the Company reported an $847,000 impairment recovery against a previously impaired Australian exploration well. This was partially offset by the final costs billed for the Kingtree well drilled and abandoned in October 2011.

In the nine months ended December 31, 2011 the Company reported a $4,089 impairment loss against exploration and evaluation assets. The impairment related to costs incurred on permit AC/P24 which were determined to be impaired after drilling the Kingtree well in October 2011.

Finance Income

Finance Income ($000s)					Three Months Ended December 31					Nine Months Ended December 31
		2012		2011	**% Change**		**2012**		2011	% Change
	$	**8**	**$**	174	(95)	**$**	**165**	$	482	(66)

The Company is receiving interest on guaranteed investment certificates and term deposits. The decrease in interest income is primarily attributable to reduced principal amount of short-term deposits from the prior year periods.

Finance Expenses

Finance Expenses ($000s)					Three Months Ended December 31					Nine Months Ended December 31
		2012		2011	% Change		**2012**		2011	% Change
Accretion expense on decommissioning liabilities	**$**	**1**	$	2	(50)	**$**	**5**	$	4	25
Performance Security Guarantee fee		**4**		1	300		**27**		45	(40)
Finance expenses	**$**	**5**	$	3	67	**$**	**32**	$	49	(35)

The Performance Security Guarantee fee is paid to Export Development Canada for security guarantee for onshore and offshore India work programs. The reduced fee is a result of the work program being partially fulfilled.

Funds from (used in) Operations and Net Loss

For the three months ended December 31, 2012 funds from operations was $481,000 or $0.01 per basic and diluted share compared to funds used in operations of $402,000 or $0.01 per basic and diluted share in the 2011 quarter. The changes in non-cash working capital are removed from the IFRS measure cash flow from (used in) operations to arrive at the non-IFRS measure funds from (used in) operations (see reconciliation on page 7).

The net loss for the three months ended December 31, 2012 was $151,000 or $0.00 per basic and diluted share compared to a loss of $477,000 or $0.01 per basic and diluted share in the 2011 quarter. The reduced loss was due to increased production in the current quarter.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	Three Months Ended December 31			Nine Months Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
Geological and geophysical	**$ 121**	$ 4,416	(97)	**$ 2,810**	5,294	(47)
Drilling	**7,083**	(251)	NA	**16,155**	1,813	791
Drilling Rig	**154**	-	-	**4,488**	-	-
Completions	**2,110**	100	2,010	**3,628**	1,498	142
Total oil & gas expenditures	**9,468**	4,265	122	**27,081**	8,605	215
Office	**7**	-	-	**19**	-	-
Total expenditures	**$ 9,475**	$ 4,265	122	**$ 27,100**	$ 8,605	215
Exploration & evaluation expenditures	**$ 7,236**	$ 4,174	73	**$ 15,713**	$ 8,166	92
Development & production expenditures	**2,085**	91	2,191	**6,899**	439	1,472
Property, plant and equipment	**154**	-	-	**4,488**	-	-
Total net expenditures	**$ 9,475**	4,265	122	**$ 27,100**	$ 8,605	215

The Company incurred $2,612,000 in seismic expenditures on its onshore India permit CY-ONN-2005/1 to complete a 575 square kilometer 3D seismic shoot and a 75 square kilometer high resolution 3D seismic shoot in the nine months ended December 31, 2012.

In the nine months ended December 31, 2012, drilling and completion expenditures were incurred to drill and complete four Cuisinier appraisal wells on the Company's ATP 752 permit. Costs were also incurred to prepare for the Company's first operated drilling activities in Australia including regulatory, health, safety and environmental costs for ATP 732, the Company's 100% owned permit in the Cooper Basin. A three well drilling program was planned with the first well, Caracal-1, being drilled and completed at December 31, 2012. Currently a fracture stimulation and appraisal drilling program is being planned for the Caracal project, in parallel, a detailed review of existing 3D seismic data on this block is being carried out

Expenditures of $1,751,000 were incurred to purchase an Ideco H-44 drilling rig. The Company spent a further $2,737,000 to transport the rig to Australia from its point of purchase, to clear customs, to buy certain ancillary equipment required for drilling operations and to make the rig ready for use.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. At February 12, 2013, there were 52,110,117 common shares issued and outstanding.

Effective December 21, 2012, the Company granted 1,150,000 stock options at an exercise price of $0.58. These options have a five-year term, vest one-third after one year and one-third on each of the next two anniversary dates.

At February 12, 2012, there were 4,249,998 employee stock options outstanding with an average exercise price of $0.98 per share. Of these, 2,021,665 have vested and are exercisable at an average price of $1.09 per share. These options expire between 2013 and 2018 with an average remaining life of 3.6 years.

Trading History	Three Months Ended December 31			Nine Months Ended December 31		
	2012	2011	% Change	**2012**	2011	% Change
High	**$ 1.09**	$ 1.48	(26)	**$ 1.09**	$ 2.06	(47)
Low	**0.49**	0.72	(32)	**0.49**	0.72	(32)
Close	**$ 0.56**	$ 0.80	(30)	**$ 0.56**	$ 0.80	(30)
Volume (000s)	**8,751**	5,070	73	**15,372**	15,401	-
Shares outstanding (000s) Basic and diluted	**52,110**	52,110	-	**52,110**	52,110	-
Weighted average shares outstanding (000s) Basic and diluted	**52,110**	52,088	-	**52,110**	51,282	2

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2012 the Company had a working capital deficit of of $1.4 million, including cash and short-term deposits of $2.3 million and restricted cash of $0.1 million, compared to working capital of $25.7 million, including cash and short term deposits of $26.9 million and restricted cash of $0.1 million at March 31, 2012.

On January 25, 2013 the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million of short-term, convertible and non-convertible notes. The Private Placement consists of the placement of: (i) $1,750,000 aggregate principal amount of non-convertible notes ("Non-Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days; and (ii) $1,750,000 aggregate principal amount of convertible notes ("Convertible Notes" and together with the Non-Convertible Notes, the "Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days. The Convertible Notes will be convertible into common shares ("Common Shares"), at the option of the holder, in the capital of the Company at a conversion price equal to the lower of the five day volume weighted average price of the Common Shares as at: (A) the issue date of the Convertible Notes, and (B) the date of conversion of some or all of the principal amount of the Convertible Notes; provided that the conversion price shall not be lower than that conversion price that would require the Company to seek shareholder approval of the issuance of Common Shares on conversion of some or all of the principal amount of the Convertible Notes pursuant to the policies of the Toronto Stock Exchange ("TSX"). All interest payable under the Notes is payable in cash. The principal amount of the Notes shall be redeemable, at the Company's option, in whole or in part, at any time and from time to time, for cash, provided that any partial redemption is subject to a minimum redemption in the amount of $50,000 of aggregate principal amount outstanding. Certain directors, who are shareholders of the Company, acquired $1,500,000 principal amount of the Convertible Notes and $1,500,000 principal amount of the Non-Convertible Notes issued pursuant to the Private Placement.

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 are not expected to be sufficient to meet all of its working capital requirements for the next twelve months and its commitments under its capital program (see Note 11 of the interim financial statements for the three and nine months ended December 31, 2012), and accordingly the Company will need to raise additional funding through some combination of equity capital, debt financing, joint venture partnership(s) or farm out arrangement(s) or divest some non-core assets . In the event that additional funding cannot be obtained , $0.8 million in capital costs associated with permit AC/P 47 and CY-OSN-2009/1 will be impaired. There is no assurance that additional funds will be available to the Company or, if available, that the funds will be available on terms acceptable to the Company.

The Company expects cash generation to increase over the year as production from Cuisinier ramps up with completion of the tie-in to the Cook facility, however predicting events beyond the Company’s control carries uncertainty. Near the year ended March 31, 2013 the Company should be producing sufficient cash flow to fund ongoing exploration commitments, other than those associated with AC/P 47 and CY-OSN-2009/1 referred to above. However some external financing would be prudent to meet partner drilling commitments and strengthen the Company’s Balance Sheet. Management is pursuing a number of alternatives simultaneously that could provide necessary capital while, at the same time, maintaining or enhancing the underlying per share value. These initiatives include farm out discussions and potential sale of some non-core assets.

COMMITMENTS

Pursuant to current production sharing contracts (“PSC”), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. Additional commitments are reflected where the Company has agreed with joint venture partners to proceed with activities. The costs of these activities are based on minimum work budgets included in bid documents and have not been provided for in the financial statements. Actual costs will vary from budget. See Note 3 of the financial statements for further details with respect to financing alternatives for fulfilling these obligations.

Country and Permit	**Work Program**	**Obligation Period Ending**	**Estimated Expenditure (net) (millions CAD$)**[(1)]
Onshore Australia – ATP 752 Cuisinier	Cuisinier to Cook pipeline, facilities upgrade, drill 4 appraisal wells	January to July, 2013	$3.9
Offshore Australia – AC/P47	750km^2 3D seismic	January 2, 2013[(2)]	$7.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$ 4.3
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014[(3)]	$ 5.2

[(1)] Translated at December 31, 2012 exchange rate of US $1.0000 = CAD $0.9966 and AUD $1.0000 = CAD $1.0336
[(2)] Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA) to January 2, 2013. Refer to Note 3 of the financial statements for measurement uncertainty associated with this permit. A meeting has now been set up for March, 2013 with the regulator to discuss the future of this permit.
[(3)] Refer to Note 2 of the financial statements for measurement uncertainty associated with this permit.

Guarantees – India Permits

($000s) CAD	**Quarter Ended December 31, 2012**	**Year ended March 31, 2012**
CY-ONN-2005/1 – Onshore India – year 1	**$ –**	**$ 1,104**
CY-OSN-2005/1 – Onshore India – year 2	**819**	**820**
CY-OSN-2009/1 – Offshore India	**151**	**151**
Total Guarantees	**$ 970**	**$ 2,075**

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 December 31, 2012, 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	$ 1,058	$ 246	$ 433	$ 379	$ –
Decommissioning obligations	357	60	–	–	297
Total contractual obligations	$ 1,415	$ 306	$ 433	$ 379	$ 297

CONTINGENCIES

Final application for grant of permit ATP 934 has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the final Ministerial Grant of the tenement is received. Potential legislative changes may result in a lower commitment than shown in the table below. The Company holds a 50% operating interest in this permit. Work program consists of 500 km of 2D seismic and up to seven wells.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)
Onshore Australia – ATP 934P	Awaiting Ministerial approval before granting of ATP	4 years after grant of ATP	$ 12.1

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	**Dec. 31 2012**	Sep. 30 2012	Jun. 30 2012	Mar. 31 2012	Dec. 31 2011	Sep. 30 2011	Jun. 30 2011	Mar. 31 2011
Petroleum and natural gas sales	**$ 1,937**	$ 437	$ 498	$ 622	$ 1,328	$ 1,017	$ 1,319	$ 691
Cash from (used-in) operations	**(378)**	315	(759)	486	(417)	159	(1,371)	(725)
Per share Basic and diluted	**(0.01)**	0.01	(0.01)	0.01	(0.01)	0.00	(0.03)	(0.02)
Funds from (used in) operations[1]	**481**	(471)	(62)	(635)	(402)	(430)	7	(669)
Per share Basic and diluted	**0.01**	(0.01)	0.00	(0.01)	0.00	(0.01)	0.00	(0.02)
Net loss	**$ (151)**	$ (845)	$ (211)	$ (1,424)	$ (477)	$ (4,247)	$ (1,061)	$ (890)
Per share Basic and diluted	**(0.00)**	(0.02)	0.00	(0.03)	(0.01)	(0.08)	(0.02)	(0.03)
Capital expenditures	**$ 9,475**	$ 10,299	$ 7,326	$ 2,233	$ 4,265	$ 2,407	$ 1,933	$ 1,978
Working capital	**(1,436)**	7,578	18,425	25,722	28,798	33,109	35,691	14,063
Total assets	**47,584**	46,557	44,484	43,696	44,899	45,696	51,072	25,829
Shares outstanding Basic and diluted	**52,110**	52,110	52,110	52,110	52,110	51,961	51,961	37,795
Operations								
Average daily production								
Natural gas (mcf/d)	**110**	159	225	304	271	196	249	348
Oil and NGLs (bbls/d)	**185**	38	51	52	112	97	110	59
Combined (boe/d)	**203**	65	89	103	157	130	152	117
Netback ($/boe)	**$ 60.92**	$ 40.07	$ 24.51	$ 27.27	$ 49.89	$ 51.42	$ 48.92	$ 31.31

(1) See "Non-IFRS Measurements" on page 7 of this MD&A.

Beginning in the quarter ended March 31, 2011 and continuing through to the quarter ended December 31, 2011, oil volumes were increasing due to commencement of production from the Cuisinier 1 well in the Cooper Basin of Australia in May 2010 and the Cuisinier 2 and 3 wells in the quarter ended September 2011. Oil sales beginning in January 2012 have been impacted by the temporary shut in of Cuisinier 1 on January 13, 2012 and Cuisinier 2 and 3 in August and September 2012 while the Company waits for approval of a Production License. Oil volumes increased in the quarter ended December 31, 2012 due to commencement of production from Cuisinier 4, 5, 6 and Cuisinier North 1 and Barta North 1. These well were drilled in mid 2012 and started producing under a six month Extended Production Test in October 2012.

Gas volumes declined in the quarter ended September 30, 2011 due to a plant turnaround at the Oak B.C. property and are in a general decline due to natural reservoir declines. Gas volumes also declined in the quarter ended June 30, 2012 due to the removal of a rental screw compressor (due to low gas prices and the cost of the rental plus associated maintenance) and an unscheduled plant shutdown at the Oak property due to a leak in the line to the flare stack. Gas volumes declined in the quarter ended September 30, 2012 as the Company's Oak B.C. gas property was shut in due to low gas prices. This property recommenced production in December 2012.

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 ineffective at March 31, 2012 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.

RISK FACTORS

There are a number of risk factors facing companies that participate in the International oil and gas industry. A complete list of risk factors are provided in Bengal's Annual Information Form dated June 29, 2012 filed on SEDAR at www.sedar.com.

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;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective and whether 3 wells will be drilled on this block by March 2014;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1;*
- *Continuation of exploration, development activities on Permit AC/P 47 offshore Australia and whether the Company will be granted an extension to the time period to complete the work program on this permit and whether a farm-out partner will be found on acceptable terms to the Company and if not, whether the Company will shoot seismic on this permit;*
- *Obtaining Ministerial Grant of the tenement on ATP 934P in Australia and commencement of exploration activities;*
- *That further drilling activities on ATP 732P will occur;*
- *That planned drilling of five wells will occur on ATP 752P in calendar Q1 and Q2 of 2013 that production from all wells will continue as expected and that a production license will be granted for the Cuisinier field and it will*

commence full production from all wells and that the Cuisinier to Cook Pipeline will be completed in calendar Q1 of 2013.

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, that 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
Allens Arthur Robinson • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
West Pac Bank • Brisbane, Australia
Commonwealth Bank • Brisbane, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS

Bryan Mills Iradesso • Calgary, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Stephen N. Inbusch
Dr. Brian J. Moss
R. D. (Bob) Steele
Ian J. Towers (Chairman)
W.B. (Bill) Wheeler

DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

James B. Howe (Chairman)
Stephen N. Inbusch
R. D. (Bob) Steele
W.B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Stephen N. Inbusch
Dr. Brian J. Moss

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan C. Goudie, Chief Financial Officer
D. Garrett Wilson, Vice President, Engineering and Operations
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX:BNG

Condensed Consolidated Interim Financial Statements (unaudited)

Three and nine months ended December 31, 2012 and 2011

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

(unaudited)

As at	Notes	December 31, 2012	March 31, 2012
ASSETS			
Current assets:			
Cash and cash equivalents		**$ 2,345**	$ 26,934
Restricted cash		**140**	135
Accounts receivable		**2,874**	1,009
Prepaid expenses and deposits		**93**	127
		5,452	28,205
Non-current assets:			
Exploration and evaluation assets	**4**	**26,292**	10,526
Petroleum and natural gas properties	**5**	**11,180**	4,735
Property, plant and equipment	**6**	**4,660**	230
		42,132	15,491
Total assets		**$ 47,584**	$ 43,696
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		**$ 6,888**	$ 2,483
Non-current liabilities:			
Decommissioning liabilities	**7**	**357**	228
Shareholders' equity:			
Share capital		**$ 86,246**	$ 86,246
Contributed surplus		**6,293**	5,779
Accumulated other comprehensive income		**764**	717
Deficit		**(52,964)**	(51,757)
		40,339	40,985
Total liabilities and shareholders' equity		**$ 47,584**	$ 43,696

Commitments (note 11)

Subsequent event (note 13)

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF LOSS AND COMPREHENSIVE INCOME (LOSS)

(Thousands of Canadian dollars, except per share amounts)

(unaudited)

For the periods ended December 31,	Notes	Three months 2012	Three months 2011	Nine months 2012	Nine months 2011
Income					
Petroleum and natural gas revenue		**$ 1,937**	$ 1,328	**$ 2,872**	$ 3,664
Royalties		**(172)**	(121)	**(255)**	(337)
		1,765	1,207	**2,617**	3,327
Operating expenses					
General and administrative		**665**	853	**2,623**	2,641
Operating and transportation		**623**	486	**1,032**	1,324
Depletion and depreciation	**5,6**	**521**	126	**710**	327
Pre-licensing and impairment	**4**	**10**	(251)	**(748)**	4,089
Exploration and evaluation expenses		**–**	293	**–**	293
Share-based compensation		**107**	169	**360**	686
		1,926	1,676	**3,977**	9,360
Operating loss		**(161)**	(469)	**(1,360)**	(6,033)
Other income (expenses)					
Finance income		**8**	174	**165**	482
Finance expenses		**(5)**	(3)	**(32)**	(49)
Foreign exchange gain (loss)		**7**	(179)	**20**	(185)
		10	(8)	**153**	248
Net Loss		**(151)**	(477)	**(1,207)**	(5,785)
Exchange differences on translation of foreign operations		**366**	520	**47**	749
Total comprehensive income (loss) for the period		**$ 215**	$ 43	**$ (1,160)**	$ (5,036)
Loss per share	**8**				
- Basic & Diluted		**$ (0.00)**	$ (0.01)	**$ (0.02)**	$ (0.11)
Weighted average number of shares outstanding (000s)	**8**				
- Basic & Diluted		**52,110**	52,088	**52,110**	51,282

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

(unaudited)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2011	37,794,549	$ 62,595	$ 705	$ 4,189	$ 95	$ (44,586)	$ 22,998
Net loss for the period	-	-	-	-	-	(5,785)	(5,785)
Comprehensive loss for the period	-	-	-	-	749	-	749
Issue of share capital (Note 7)	-	23,651	-	(146)	-	-	23,505
Expiry of warrants	-	-	(705)	705	-	-	-
Share-based payments	-	-	-	688	-	-	688
Balance at December 31, 2011	**52,110,127**	**$ 86,246**	**$ –**	**$ 5,436**	**$ 844**	**$ (50,371)**	**$ 42,155**
Balance at April 1, 2012	**52,110,177**	**$ 86,246**	**$ –**	**$ 5,779**	**$ 717**	**$ (51,757)**	**$ 40,985**
Net loss for the period	**-**	**-**	**-**	**-**	**-**	**(1,207)**	**(1,207)**
Comprehensive income for the period	**-**	**-**	**-**	**-**	**47**	**-**	**47**
Share-based payments - expensed	**-**	**-**	**-**	**360**	**-**	**-**	**360**
Share-based payments - capitalized	**-**	**-**	**-**	**154**	**-**	**-**	**154**
Balance at December 31, 2012	**52,110,177**	**$86,246**	**$ –**	**$ 6,293**	**$ 764**	**$ (52,964)**	**$ 40,339**

See accompanying notes to the condensed consolidated interim financial statements.

BENGAL ENERGY LTD.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

(unaudited)

For the periods ended December 31,	Notes	Three months 2012	Three months 2011	Nine months 2012	Nine months 2011
Operating activities					
Net loss		**$ (151)**	$ (477)	**$ (1,207)**	$ (5,785)
Non-cash items:					
Depletion and depreciation		**521**	126	**710**	327
Pre-licensing and impairment		**10**	(251)	**99**	4,089
Accretion		**1**	2	**5**	4
Share-based compensation		**107**	169	**360**	686
Unrealized foreign exchange (gain) loss		**(7)**	29	**(19)**	145
Change in non-cash working capital	**10**	**(859)**	(15)	**(770)**	(804)
Net cash flow used in operating activities		**(378)**	(417)	**(822)**	(1,628)
Investing activities					
Exploration and evaluation expenditures		**(7,236)**	(4,174)	**(15,713)**	(8,166)
Petroleum and natural gas properties		**(2,085)**	(91)	**(6,899)**	(439)
Property, plant & equipment		**(154)**	–	**(4,488)**	–
Change in restricted cash		**(5)**	–	**(5)**	1,092
Changes in investing non-cash working capital	**10**	**(192)**	(1,608)	**3,195**	(229)
Net cash flow used in investing activities		**(9,672)**	(5,873)	**(23,910)**	(7,742)
Financing activities					
Proceeds from issuance of shares, net of issuance costs		**–**	27	**–**	23,505
Changes in financing non-cash working capital	**10**	**–**	–	**–**	(82)
Net cash flow from financing activities		**–**	27	**–**	23,423
Impact of foreign exchange on cash and cash equivalents		**88**	132	**143**	463
Net increase (decrease) in cash and cash equivalents		**$ (9,962)**	$ (6,131)	**$ (24,589)**	$ 14,516
Cash and cash equivalents, beginning of period		**12,307**	35,247	**26,934**	14,600
Cash and cash equivalents, end of period		**$ 2,345**	$ 29,116	**$ 2,345**	$ 29,116

See accompanying notes to condensed consolidated interim financial statements.

1. REPORTING ENTITY:

Bengal Energy Ltd (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration for and development of oil and gas reserves in Australia, India and Canada. The condensed consolidated interim financial statements (the "financial statements") of the Company as at December 31, 2012 and for the three and nine months ended December 31, 2012 and 2011 are comprised of the Company and its wholly owned subsidiaries Bengal Energy International Inc. and Bengal Energy (Australia) Pty Ltd. which are incorporated in Canada and Australia respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

Bengal's principal place of business and registered office is located at 1810, 801 6th Ave SW, Calgary, Alberta, Canada, T2P 3W2.

2. BASIS OF PREPARATION

These condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". These condensed consolidated interim financial statements do not include all of the information required for full annual financial statements.

These condensed consolidated interim financial statements are stated in Canadian dollars and have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended March 31, 2012. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended March 31, 2012.

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 had $2.3 million in cash (March 31, 2012 - $26.9 million), $0.1 million in restricted cash (March 31, 2012 - $0.1 million) and a working capital defiency of $1.4 million at December 31, 2012 (March 31, 2012 – working capital surplus of $25.7 million).

The Company's existing cash and cash equivalents and operating cash flows are not expected to be sufficient to meet all of its working capital requirements for the next twelve months and its commitments under its capital program (see Note 11), and accordingly the Company will need to raise additional funding through some combination of equity capital, debt financing, joint venture partnership(s) or farm out arrangement(s) or divest some non-core assets. In the event that additional funding cannot be obtained, $0.8 million in capital costs associated with permit AC/P 47 and CY-OSN-2009/1 will be impaired. There is no assurance that additional funds will be available to the Company or, if available, that the funds will be available on terms acceptable to the Company.

These interim consolidated financial statements were authorized for issuance by the Board of Directors on February 12, 2013.

3. SIGNIFICANT ACCOUNTING POLICIES

a) Property and equipment – drilling rig

i) Recognition and measurement

Initial costs related to the acquisition or construction of property and equipment are capitalized and accumulated by rig or a component thereof.

Subsequent to initial recognition, items of property and equipment are measured at cost less accumulated depreciation and accumulated impairment losses. When significant parts of an item of property and equipment have different useful lives, they are accounted for as separate items (major components).

Subsequent costs are included in the related asset's carrying amount or recognized as a separate asset, as appropriate, only when is it probable that future economic benefits associated with the item will flow to the group and the cost of the item can be measured reliably. All other repairs and maintenance are recorded in profit and loss.

Gains and losses on disposal of an item of property and equipment are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in profit and loss.

ii) Depreciation

The net carrying value of drilling and workover rig components is depreciated using the unit of production method so as to depreciate the cost, less an estimated residual value of 5%, over the days in which the rig components are expected to be utilized during its useful life. Utilization days for depreciation purposes exclude initial mobilization, inter-well moves and final demobilization.

The estimated useful lives for certain rig components:

Mast and substructure	6,500 days
Draw works, rig & carrier power, genset, small wellsite office, storage containers	5,000 days
Mud tanks & mud pumps, vehicles, various small tools & handling tools, HSE equipment	3,000 days
Rebuild, inspections, re-certifications	1,000 days

Useful lives and the depreciation methods are examined on an annual basis and adjustments, where applicable, are made on a prospective basis.

iii) Impairment

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. The recoverable amount of an asset is the greater of its value in use and its fair value less costs to sell

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from the cash generating unit.

An impairment loss is recognized if the carrying amount of an asset exceeds its estimated recoverable amount. Impairment losses are recognized in profit and loss.

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

		Exploration and Evaluation Expenditures
Balance at April 1, 2011	$	7,064
Additions		10,213
Capitalized share-based compensation		29
E&E impairment loss		(4,194)
Transfer to petroleum and natural gas properties		(2,705)
Exchange adjustments		119
Balance at March 31, 2012	**$**	**10,526**
Additions		15,713
Capitalized share-based compensation		128
E&E impairment loss		(99)
Exchange adjustments		24
Balance at December 31, 2012	**$**	**26,292**

Exploration and evaluation assets consist of the Company's exploration projects in Australia and India which are pending the determination of proved or probable reserves. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling and completion costs until the drilling of wells is complete and the results have been evaluated.

The original time period in which to complete the seismic work program on the offshore Australia AC/P 47 permit expired on March 2, 2012. On October 19, 2012, the Company was granted an extension to January 2, 2013 for the time period for completing the work program from the National Offshore Petroleum Titles Administrator (NOPTA). A meeting has now been set for March 2013 with the regulators to discuss the future of this permit. The Company is attempting to farm out this work program and if unsuccessful in its efforts to farm out or obtain a further extension, the work program will not be fulfilled and $0.8 million in costs will be impaired.

As a result of a final settlement agreement, $0.8 million of previously impaired costs for the drilling of the abandoned Hudson well in a prior year were recovered in the nine months ended December 31, 2012 on the statement of loss and comprehensive loss.

5. PETROLEUM AND NATURAL GAS PROPERTIES

		Petroleum and Natural Gas Properties		Corporate Assets		Total
		$000s		**$000s**		**$000s**
Cost:						
Balance at April 1, 2011		2,168		196		2,364
Additions		520		105		625
Capitalized share-based compensation		2		–		2
Change in asset retirement obligation		67		–		67
Transfers from E&E assets		2,705		-		2,705
Exchange adjustments		35		-		35
Balance at March 31, 2012	**$**	**5,497**	**$**	**301**	**$**	**5,798**
Additions		6,774		125		6,899
Capitalized share-based compensation		11		–		11
Change in asset retirement obligation		124		–		124
Exchange adjustments		133		–		133
Balance at December 31, 2012	**$**	**12,539**	**$**	**426**	**$**	**12,965**

	Petroleum and Natural	Corporate Assets	Total

	Gas Properties		
	$000s	$ 000s	$000s
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2011	283	51	334
Depletion and depreciation charge	383	37	420
Exchange adjustments	(2)	-	(2)
Impairment expense	311	-	311
Balance at March 31, 2012	**$ 975**	**$ 88**	**$ 1,063**
Depletion and depreciation charge	580	57	637
Exchange adjustments	85	-	85
Balance at December 31, 2012	**$ 1,640**	**$ 145**	**$ 1,785**
Net book value			
At March 31, 2012	**$ 4,522**	**$ 213**	**$ 4,735**
At December 31, 2012	**$ 10,899**	**$ 281**	**$ 11,180**

The calculation of depletion for the three months ended December 31, 2012 included $28.3 million and $0.7 million for estimated future development costs associated with proved and probable reserves in Australia and Canada respectively (March 31, 2012 - $0.8 million and $0.7 million).

6. PROPERTY, PLANT AND EQUIPMENT

	Rig Equipment
Balance at March 31, 2011	$ –
Additions	230
Balance at March 31, 2012	**$ 230**
Additions	4,488
Capitalized share-based compensation	15
Balance at December 31, 2012	**$ 4,733**
Accumulated depletion, depreciation and impairment losses:	
Balance at March 31, 2011 and 2012	**$ –**
Depreciation charge	73
Balance at December 31, 2012	**$ 73**
Net book value	
At March 31, 2012	**$ 230**
At December 31, 2012	**$ 4,660**

On April 5, 2012 the Company purchased an Ideco H-44 drilling rig. The purchase price of the Rig was US $1.75 million. Additional costs have been incurred to transport the rig from its point of purchase, prepare the rig and acquire certain ancillary equipment required for drilling operations. This rig was used to drill, case and test the Caracal-1 well.

7. DECOMMISSIONING LIABILITIES

	December 31, 2012	March 31, 2012
Decommissioning liabilities, beginning of period	**$ 228**	$ 159
Revision	**–**	67
Additions	**124**	–
Expenditures	**–**	(3)
Accretion	**5**	5
Decommissioning liabilities, end of period	**$ 357**	$ 228

The Company's decommissioning liabilities result from its ownership interest in oil and natural gas assets including well sites and facilities. The total decommissioning liability is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning liabilities to be $357,000 as at December 31, 2012 (March 31, 2012 - $228,000) based on an undiscounted, inflation adjusted, total future liability of $427,000 (March 31, 2012 - $283,000). These payments are expected to be made over the next 14 years with the majority of costs to be incurred between 2020 and 2026. A discount factor, being the risk-free rate related to the liability (which is primarily the Australian risk free rate), of between 2.0% and 3.0% (March 31, 2012 – 2.0% to 3.0%) and an inflation rate of between 2.0% and 3.25% (March 31, 2012 – 2.0% to 3.0%) were used to calculate the net present value of the decommissioning liability.

8. LOSS PER SHARE

Loss per share is calculated based on net loss and the weighted-average number of common shares outstanding. The Company has recorded a loss in each of the periods presented and therefore any addition to basic shares outstanding is anti-dilutive.

At December 31, 2012, there were 4,249,998 (March 31, 2012 – 3,611,665) options considered anti-dilutive.

The table below shows share option activity for the nine months ended December 31, 2012:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2012	**3,611,665**	**$ 1.14**
Granted	1,150,000	0.58
Forfeited	(136,667)	1.10
Expired	(375,000)	1.30
Outstanding at December 31, 2012	**4,249,998**	**$ 0.98**
Exercisable at December 31, 2012	2,021,665	$ 1.09

The options were granted in the current quarter and have an exercise price of $0.58, a five year life and vest one third each year starting at the end of the first year. The fair value of options granted was $0.39 and was estimated on the date of grant using the Black-Scholes option-pricing model and the following assumptions: a risk-free rate of 2%, expected life of 5 years, expected volatility of 86% and an estimated forfeiture rate of 6%. The fair value of the options will be charged to earnings over the three year vesting period of the options.

9. FINANCIAL RISK MANAGEMENT

Foreign currency Risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives Canadian dollars for sales in Canada, U.S. dollars for Australian oil sales and incurs expenditures in Australian, Canadian and U.S. currencies. Having sales and expenditures denominated in three currencies spreads the impact of individual currency fluctuations.

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

The table below shows the Company's exposure to foreign currencies for its financial instruments (denominated in local currencies):

As at December 31, 2012 ($000s)			
	CAD	**AUD**	**USD**
Cash and cash equivalents	$ 1,199	$ 730	$ 391
Restricted cash	140	–	–
Accounts receivable	99	989	1,771
Accounts payable and accrued liabilities	(355)	(6,335)	(6)
	$ 1,083	$ (4,616)	$ 2,156

Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at December 31, 2012, Bengal's receivables consisted of $2.2 million (March 31, 2012 - $0.6 million) from joint venture partners and $0.7 million (March 31, 2012 - $0.4 million) of other trade receivables.

In Australia, production is purchased by a consortium led by one of Australia's largest public oil and gas companies which is also the operator of Bengal's production. Bengal has a Crude Oil Purchase Agreement with this purchaser and has not experienced any collection problems to date.

Cash calls paid to Bengal's Australian joint venture partners are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint venture receivables by approving significant spending by partners prior to expenditure and only paying the cash call shortly before the funds are to be spent.

At December 31, 2012, the Company had $0.1 million (March 31, 2012 - $0.1 million) that were considered past due (past due is considered greater than 90 days outstanding). The Company does not believe there is any collection risk with the past due receivable.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at December 31, 2012 (March 31, 2012 - $nil) and did not write-off any receivables at December 31, 2012 or March 31, 2012.

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

10. CHANGES IN NON-CASH WORKING CAPITAL

Periods Ended ($000s)		December 31, 2012		December 31, 2011
Accounts receivable	$	(1,865)	$	(965)
Prepaid expenses and deposits		34		(59)
Accounts payable and accrued liabilities		4,256		(91)
Total	$	2,425	$	(1,115)
Relating to:				
Operating	$	(770)	$	(804)
Financing		–		(82)
Investing		3,195		(229)
Total	$	2,425	$	(1,115)

Note – changes in working capital consider elements of unrealized foreign exchange differences on assets and liabilities denominated in a foreign currency.

The following represents the cash interest received in each period.

Quarters Ended ($000s)		December 31, 2012		December 31, 2011
Cash interest received	$	272	$	378

11. COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. Additional commitments are reflected where the Company has agreed with joint venture partners to proceed with activities. The costs of these activities are based on minimum work budgets included in bid documents and have not been provided for in the financial statements. Actual costs will vary from budget. See Note 2 for further details with respect to financing alternatives for fulfilling these obligations.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Onshore Australia – ATP 752 Cuisinier	Cuisinier to Cook pipeline, facilities upgrade, drill 4 appraisel wells	January to July, 2013	$3.9
Offshore Australia – AC/P47	750km^2 3D seismic	January 2, 2013(2)	$7.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$ 4.3
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014(3)	$ 5.2

(1) Translated at December 31, 2012 exchange rate of US $1.0000 = CAD $0.9966 and AUD $1.0000 = CAD $1.0336

(2) Bengal received an extension to the time period to complete the scheduled work commitment for this offshore permit from the National Offshore Petroleum Titles Administrator (NOPTA) to January 2, 2013. Refer to Note 2 for measurement uncertainty associated with this permit. A meeting has now been set for March, 2013 with the regulator to discuss the future of this permit.

(3) Refer to Note 2 for measurement uncertainty associated with this permit.

At December 31, 2012 the Company had the following lease commitment for office space in Canada:

($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 1,058	$ 246	$ 433	$ 379	$ –

Effective April 1, 2012 the Company has entered into a new head office lease in Calgary, Canada for a term of five years.

12. CONTINGENCIES

Final application for the grant of permit ATP 934 has been filed with the Queensland Government regulatory authority. No further activity is planned on this permit until the final Ministerial Grant of the tenement is received. Potential legislative changes may result in a lower commitment than shown in the table below; The Company holds a 50% operating interest in this permit. The Work program consists of 500 km of 2D seismic and up to seven wells.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)
Onshore Australia – ATP 934P	Awaiting Ministerial approval before granting of ATP	4 years after grant of ATP	$ 12.1

13. SUBSEQUENT EVENT

On January 25, 2012 the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million of short-term, convertible and non-convertible notes. The Private Placement consists of the placement of: (i) $1,750,000 aggregate principal amount of non-convertible notes ("Non-Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days; and (ii) $1,750,000 aggregate principal amount of convertible notes ("Convertible Notes" and together with the Non-Convertible Notes, the "Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days. The Convertible Notes will be convertible into common shares ("Common Shares"), at the option of the holder, in the capital of the Company at a conversion price equal to the lower of the five day volume weighted average price of the Common Shares as at: (A) the issue date of the Convertible Notes, and (B) the date of conversion of some or all of the principal amount of the Convertible Notes; provided that the conversion price shall not be lower than that conversion price that would require the Company to seek shareholder approval of the issuance of Common Shares on conversion of some or all of the principal amount of the Convertible Notes pursuant to the policies of the Toronto Stock Exchange ("TSX"). All interest payable under the Notes is payable in cash. The principal amount of the Notes shall be redeemable, at the Company's option, in whole or in part, at any time and from time to time, for cash, provided that any partial redemption is subject to a minimum redemption in the amount of $50,000 of aggregate principal amount outstanding. Certain directors, who are also shareholders of the Company, acquired $1,500,000 principal amount of the Convertible Notes and $1,500,000 principal amount of the Non-Convertible Notes issued pursuant to the Private Placement.

14. SEGMENTED INFORMATION

As at December 31, 2012, the Company has three reportable operating segments being the Australian, Canadian and Indian oil and gas operations. India is considered to be in the pre-production stage.

Revenue reported below represents revenue generated from external customers. There were no inter-segment sales in any of the reported periods.

The accounting policies of the reportable segments are the same as the group’s accounting policies. Segment profit represents the profit earned by each segment without allocation of central administration costs and directors' salaries, finance costs and income tax expense. This is the measure reported to the chief operating decision maker for the purposes of resource allocation and assessment of segment performance.

For the nine months ended December 31, 2012 ($000s)	Australia	Canada	India	Total
Revenue	$ 2,721	$ 151	$ –	$ 2,872
Interest revenue	81	87	(3)	165
Depletion and depreciation	547	163	–	710
Net earnings (loss)	1,071	(1,708)	(570)	(1,207)
Exploration and evaluation expenditures	13,101	–	2,612	15,713
Petroleum and natural gas property expenditures	6,879	20	–	6,899
Recovery of impairment loss	748	–	–	748
Property, plant & equipment expenditures	$ –	4,488	–	4,488
As at December 31, 2012 ($000s)				
Petroleum and natural gas properties				
Cost	$ 11,750	$ 1,215	$ –	$ 12,965
Impairment losses	–	(311)	–	(311)
Accumulated depletion, depreciation and accretion	(1,037)	(437)	–	(1,474)
Net book value	$ 10,713	$ 467	$ –	$ 11,180
Exploration and evaluation assets	$ 25,644	$ –	$ 4,941	$ 30,585
Accumulated impairment loss	(4,293)	–	–	(4,293)
Net book value	$ 21,351	$ –	$ 4,941	$ 26,292
Property, plant & equipment	$ –	$ 4,733	$ –	$ 4,733
Accumulated depletion, depreciation and accretion	–	(73)	–	(73)
Net book value	$ –	$ 4,660	$ –	$ 4,660

For the nine months ended December 31, 2011 ($000s)	Australia	Canada	New cost centres [1]	Total
Revenue	$ 3,361	$ 303	$ –	$ 3,664
Interest revenue	225	234	23	482
Depletion and depreciation	229	98	–	327
Net loss	(2,922)	(2,125)	(738)	(5,785)
Exploration and evaluation expenditures	7,412	–	754	8,166
Petroleum and natural gas property expenditures	447	-	–	447
Impairment loss	(4,089)	-	–	(4,089)
As at December 31, 2011 ($000s)				
Petroleum and natural gas properties				
Cost	$ 19,146	$ 4,374	$ 451	$ 23,971
Accumulated depletion, depreciation and accretion	(16,334)	(3,640)	(451)	(20,425)
Net book value	$ 2,812	$ 734	$ –	$ 3,546
Exploration and evaluation assets	12,503	–	1,560	14,063
Accumulated impairment loss	(4,089)	–	–	(4,089)
Net book value	$ 8,414	$ –	$ 1,560	$ 9,974

(1) New cost centres include India and Ireland.

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Allens Arthur Robinson • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
West Pac Bank • Brisbane, Australia
Commonwealth Bank • Brisbane, Australia
ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

REGISTRAR AND TRANSFER AGENT

Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS

Bryan Mills Iradesso • Calgary, Canada

DIRECTORS

Chayan Chakrabarty
Peter D. Gaffney
James B. Howe
Stephen N. Inbusch
Dr. Brian J. Moss
R. D. (Bob) Steele
Ian J. Towers (Chairman)
W.B. (Bill) Wheeler

DISCLOSURE COMMITTEE

All Directors are members of the Committee

AUDIT COMMITTEE

James B. Howe (Chairman)
Stephen N. Inbusch
R. D. (Bob) Steele
W.B. (Bill) Wheeler

RESERVES COMMITTEE

Peter D. Gaffney (Chairman)
Stephen N. Inbusch
Dr. Brian J. Moss

GOVERNANCE AND COMPENSATION COMMITTEE

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

OFFICERS

Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Bryan C. Goudie, Chief Financial Officer
D. Garrett Wilson, Vice President, Engineering and Operations
Gordon R. MacMahon, Vice President, Exploration
Bruce Allford, Secretary

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