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BENGAL ENERGY LTD.

MESSAGE TO SHAREHOLDERS

I am pleased to report that through this past fiscal year ending March 31, 2014, Bengal Energy continued to execute on our focused strategy resulting in numerous key milestones being met.

Bengal's world-class assets are located in politically, fiscally and economically stable jurisdictions, featuring industry-leading netbacks bolstered by high potential impact exploration. This unique combination affords shareholders exposure to a growing and oil-weighted company with exciting exploration potential that will be largely funded through our cash flow. Building on the success we realized in our last fiscal year, Bengal commenced the largest drilling and capital program in the Company's history in March of 2014, which will be undertaken through fiscal 2015.

Over the past year, we have achieved numerous operational milestones across our Cooper Basin, Australia assets, particularly in our Cuisinier (Barta sub Block of ATP 752) and Tookoonooka (ATP 732) areas. In light of the sizeable potential of Cuisinier for longer term development as well as its ability to generate an attractive cash flow stream, Bengal elected to purchase an additional 5.4% working interest in the permit in June 2013, bringing our total interest up to 30.4%, and allowing us to realize a greater proportion of the production and booked reserves from Cuisinier.

We continued to develop Cuisinier through the year, and completed a six well drilling program with 100% success, as all wells were brought on stream as oil producers, contributing to overall production volumes for the year. Our corporate production averaged 504 boepd for the fourth quarter of fiscal 2014, an increase of 55% over the fourth quarter of fiscal 2013. Since our Cuisinier production is all ultra-light oil, our Australian netbacks are very strong, averaging $83.00 / bbl, which is significantly higher than the average netback of a producer in Western Canada. In addition to the production and cash flow that was generated, the success of this program helped to further expand the boundaries of the pool, enhance our technical team's understanding of the geological features in the area, and resulted in record reserves and value bookings for Bengal in our year end reserves evaluation.

As a direct result of our ongoing activities in Cuisinier, at fiscal year end 2014 Bengal's independent reserve evaluators assessed the net present value of our proved plus probable (2P) reserves discounted at 10% (NPV10), at $101 million, an increase of 149% over the prior year. This value is a step change above the Company's enterprise value at fiscal year end 2014, and reflects an opportunity for substantial value expansion in the market. We successfully booked 2P reserves of 3.8 million boe, an increase of 122% relative to 2013, and our total proved (1P) booked reserves of 1.7 million boe were equal to last year's 2P reserves. Based on our 1P and 2P reserves additions, we replaced ~6.4X & 13.2X our annual production, respectively. This is an incredible achievement for Bengal, and underpins the value of our company.

Our team's technical strength, persistent effort and value-focused mindset have been demonstrated emphatically through the growth in Cuisinier pool size and its asset value net to Bengal Energy. Based on our independent reserves evaluators' assessments, the pool size has grown from 0.5 million barrels (2P, gross pool oil in place) in 2010 to just under 50 million barrels in 2014, reflecting a compound annual growth rate (CAGR) of over 210%. On a proved plus probable plus possible basis, the gross pool oil in place in this year's independent reserves evaluation was assessed to be over 100 million barrels. Our working interest reserves in this field has shown a dramatic 249% CAGR from 2010 to 2014, and the NPV10 value of our share of Cuisinier reserves has shown a 203% CAGR in the same time period. These growth metrics highlight the significant and sustained achievements that our team has been able to make in terms of growing our fundamental asset value for the benefit of our shareholders.

Prior to the finalization of our year end reserves report, Bengal took steps to secure a reserves based credit facility, to backstop the funding of our ongoing Australian development program. In late May, 2014 we signed an indicative term sheet for a US $20 million secured credit facility with a leading Australian commercial bank, contemplating a three year term at attractive fixed income market rates tied to USD LIBOR. Consistent with our conservative approach to financing, we conducted a thorough stress test on our existing production base to ensure that such a facility along with our existing unsecured debt will be fully serviceable under several commodity price scenarios. Finalization of the facility is subject to the lender completing their due diligence, as well as the possibility that competing offers may be received by alternative vendors, and is expected in late June, 2014. This facility will free up internally generated cash flows for the funding of our exploration activities, including three exploration wells in Australia and three in India. Bengal is committed to securing the lowest cost source of funding with the highest level of flexibility, which offers room for expansion based on current and future reserves bookings, which have not been factored into the proposed facility terms.

With a secured source of financing, coupled with the reserve and production increases that have been realized to date in Cuisinier, we are well positioned for ongoing development. Bengal began an aggressive two-phase drilling program in March 2014, which will run through the fiscal 2015 year. During which we will drill eight development wells and two exploration wells on the Barta sub Block (in Cuisinier and other areas), plus one exploration well in a separate area called the Wompi sub Block of ATP 572. The first four development wells under Phase One were drilled in Cuisinier throughout April / May 2014, and all have been cased as future oil producers, with completion of the wells anticipated before the end of June, 2014.

As part of our program, we committed to the drilling of two exploration wells in the Barta sub Block, Koki-1 and Wicho East, which are located in Barta North, an area four km to the North of Cuisinier, in which Bengal has identified six independent structures on 3D for multi-zone exploration drilling. The Koki-1 well was drilled in early June and failed to identify commercial hydrocarbons and has been plugged and abandoned. Wicho East is expected to spud in August, 2014 and will target the Hutton zone in an independent structural closure within the Cuisinier North area. These exploration wells are intended to provide us with valuable insights regarding the future prospectivity of areas outside our core Cuisinier field. In Barta West, an area situated to the west of Cuisinier, Bengal has identified strong exploration leads from our 2D seismic interpretation, and we plan to supplement this with the acquisition of 3D seismic in 2015.

The third of our upcoming exploration wells is located in Wompi, an area Bengal holds a 38% working interest, and is situated within a well-established, oil producing fairway and offers a moderate-risk, multi-zone opportunity. Offsetting pools around Wompi have been developed targeting a deeper formation called the Hutton, which have resulted in some prolific, high impact wells. We anticipate our Wompi exploration well will spud towards the end of calendar 2014.

Also during fiscal 2014, Bengal secured an agreement with a premier Cooper Basin operator, Beach Energy Ltd, for the development of our Tookoonooka asset, which is located on the Eastern Flank of the Cooper Basin. In exchange for a 50% interest in Tookoonooka, Beach agreed to fund the drilling of two wells and the acquisition of 300 km^2 of 3D seismic for up to a maximum of AUD$11.5 million. Our strategic partnership with Beach not only provides funding for the development of Tookoonooka, but it also allows us to benefit from working with one of the Cooper Basin’s largest and most experienced operators. The first of the two wells was drilled late in calendar 2013, and although it was not commercial, it provided us with critical data, information and learnings from which to plan for the second well. Beach has now successfully completed the acquisition of the 3D seismic, and plans to select the second location from the seismic interpretation in the first quarter of calendar 2015.

In our onshore India block, our local partners have been actively advancing the regulatory and permitting aspects in order to commence drilling, and are confident that the first of three wells will spud by mid-third quarter, calendar 2014. Onshore India offers Bengal and our shareholders exposure to another potential high impact exploration play in a fiscally and politically stable country.

The past year was a pivotal one for Bengal, as our technical success significantly expanded the underlying reserves and the value in Australia, and we demonstrated our ability to grow production, reserves, cash flow and long-term value for shareholders. As a result of our technical development to date and conservative approach to financing, Bengal is stronger than ever, and poised to continue proving up the value of our world-class assets. I want to thank our strong and supportive Board, our hard-working and skilled technical team, as well as each of our shareholders for your support as we grow and further enhance the value of Bengal Energy.

Sincerely,

(signed) " Chayan Chakrabarty"

Chayan Chakrabarty

President & CEO

Note: this Message to Shareholders contains forward-looking statements and is subject to the forward-looking statement disclaimer in the Management's Discussion & Analysis for the Years Ended March 31, 2014 and 2013.

Financial Highlights:

- **Increased Production Resulted in Record Revenue –** Bengal's revenue of approximately $5.3 million in the fourth quarter was 4% lower than the $5.5 million generated in the preceding quarter due to lower realized commodity prices, but was 75% higher than the $3.0 million generated during fourth quarter of 2013. For the full year 2014, Bengal generated revenue of approximately $19.8 million, which is a 237% increase over fiscal 2013. The gain was driven by a 55% increase in production compared to the previous year, and strong pricing for the high quality crude oil produced**.**
- **Funds Flow from Operations[1] Significantly Grow Year over Year –** Bengal generated funds flow from operations of $2.2 million in the quarter ended March 31, 2014 a 23% decrease from the $2.9 million generated in the preceding quarter, due to lower netbacks and the impact of foreign exchange as the Australian dollar appreciated against the US dollar; however this reflects a 93% increase over the $1.2 million recorded in the fourth quarter of 2013. Full year 2014 funds flow from operations was $8.2 million or 645% higher than the $1.1 million generated during the twelve months ended March 31, 2013.
- **Reserves Growth Continue** – Independent third party year-end reserves evaluation to March 31, 2014 show a 122% year-over-year corporate proven and probable (2P) reserves increase, driven by significant increase of 2P reserves at Cuisinier. Based on proven (1P) and 2P reserves additions, Bengal has replaced approximately 6.4 times and 13.2 times its annual production, respectively.
- **Net Income Demonstrates Continuing Profitability** – Bengal reported net income of $150 thousand for the year compared to a loss of $1.8 million in the prior year. Before factoring in impairments of approximately $3.1 million, Bengal would have generated net income of approximately $3.2 million (EPS $0.05/share).

2014 Operational Highlights:

- **Production Volumes** – Production in the fourth quarter averaged 504 barrels of oil equivalent per day ("boepd"), an increase of 8% over the 468 boepd in the previous quarter and a 55% increase over the 325 boepd produced in Q4 2013. For the full year, Bengal's production averaged 468 boepd, a significant increase of 175% over the 170 boepd produced in 2013.
- **Cuisinier Drilling 2013** – On March 20, 2013, the Company commenced its fiscal 2014 Cuisinier drilling program, comprised of six Murta focused oil wells. The program successfully aimed to optimize the overall pool productivity and better define the ultimate pool size. All six wells were drilled and extended Bengal's 100% success rate in its Cuisinier drilling history.
- **Expanded ownership interest of Cuisinier Oil Field and the ATP 752P** – Bengal exercised its pre-emptive right to purchase an additional interest in the ATP 752P permit, bringing the Company's total ownership to 30.357% of the Cuisiner field and 38% in the Wompi block.

1. *Funds flow from operations is an additional generally accepted account principle ("GAAP measure"). The comparable International Financial Reporting Standards ("IFRS") measure is cash from operations. A reconciliation of the two measures can be found in the table on page 6 of Bengal's Annual MD&A.*

- **Receipt of Petroleum License** - Final approval of Petroleum Lease 303 (“PL303”) for the Cuisinier oil pool was granted in April 2013, allowing Bengal’s past and future Cuisinier wells to produce for up to 21 years.
- **2014 Phase 1 Cuisinier Drilling Campaign** – Commencing in March 2014, four development wells were drilled through May 2014 at Cuisiner with a 100% success rate. The wells have been cased and are awaiting completion, which is anticipated to run from mid-July through early August 2014. The Company expects tie-ins to be completed by the end of September 2014, with cash flow from the new production volumes being reflected in the first quarter of calendar 2015.
- **Onshore India Drilling Plan** - The Company continues to work with the operator of Bengal’s onshore block in India’s Cauvery Basin to finalize the necessary regulatory approvals for the drilling of three exploration wells.

Recent Developments:

- **Current Production Volumes** – Production rates in Cuisinier have been impacted by natural declines as well as operational issues encountered in the field’s largest producing well. The Cuisinier 6 well has experienced a sudden and unusual increase in water-cut as well as an increase in measured well head pressure since April 2014. Bengal, along with the operator is currently investigating the source of the water to determine a remediation strategy aimed at increasing oil production to offset this decline.
- **Extending Financial Flexibility –** Subsequent to year-end, Bengal signed an indicative term sheet for a US $20.0 million secured credit facility with a leading Australian commercial bank. Once finalized, the facility is expected to fully fund Bengal’s Australian development through March 2015, allowing the Company to fund future planned exploration activities in India and Australia with internally generated cash flows.

MANAGEMENT’S DISCUSSION AND ANALYSIS – JUNE 13, 2013

Bengal’s producing assets are predominantly situated in Australia’s Cooper Basin, a region featuring large hydrocarbon pools. The Company’s core Australian assets – Cuisinier and Tookoonooka – are situated within an area of the Basin in its infancy in terms of appraisal and development, and Bengal believes these assets offer attractive upside potential. Australia features a stable political, fiscal and economic environment in which to operate, with a favourable royalty regime for oil and gas production.

With oil pricing benchmarked to Brent, Bengal’s realized operating netbacks from Australia have averaged over C $83/bbl for the twelve months ending March 31, 2014. This strong pricing environment coupled with a growing production base contributed to the Company’s increased revenues and funds flow from operations through fiscal 2014.

AUSTRALIA

Cuisinier ("ATP") 752 Barta Block

From late March 2014 to early May 2014, Bengal carried out the first of its calendar 2014 two-phase drilling campaign in Cuisinier. The four Phase One development wells were drilled with 100% success and have now been cased and suspended awaiting completion and tie-in.

The wells targeted the oil-bearing Cretaceous Murta formation, and Bengal’s preliminary petrophysical analysis of the well logs show results comparable with Bengal’s six best Cuisinier wells drilled to date. This success rate and corresponding log data further validates Bengal's 3D seismic interpretation and its team's unique understanding of the Murta reservoir.

Completion of the four development wells is anticipated to run from mid-July through early August 2014, with the wells expected to be tied in through September 2014. Bengal anticipates the cash flow from the new production volumes to begin in the fourth quarter of calendar 2014.

The drilling program continued with the drilling of the Koki-1 exploration well in June. While the Koki-1 well failed to define a commercial hydrocarbon accumulation, a second exploration location is scheduled to be drilled in August, 2014 that will target the Hutton formation on an independent structural closure within the Cuisinier North 3D area. Following this exploration drilling, four Phase Two development / appraisal wells are expected to be drilled during the fourth quarter of calendar 2014. The timing will enable Bengal and its partners to benefit from data obtained in Phase One and to high-grade locations for the Second Phase with a view to enhance productivity and expand the boundaries of the pool.

ATP 732 Tookoonooka Block

In May 2013, the Corporation formed a joint venture (the "JV") with Beach, an Australian energy company, for the exploration and development of its 100% owned Tookoonooka Block ATP 732P in the Cooper Basin of Australia. Beach agreed to fund Bengal's share of a two well drilling and 3D seismic exploration and appraisal work program to a maximum of AUD$11.5 million, to acquire a 50% interest in ATP 732. The first of these two planned wells was drilled in December 2013 and was not deemed commercial.

Acquisition of 300 km2 of 3D seismic has been completed and processing / interpretation is ongoing. Based on the results of this work the selection and drilling of a second location within the newly expanded seismic area is anticipated for the second half of calendar 2014.

Wompi (ATP 752 – WI 38%)

The Wompi JV is planning to drill one exploration well in calendar Q3 2014 targeting Birkhead, Westbourne and Adori formations known to produce in the offsetting Bowen Field located immediately north of the proposed location. Wompi offers Bengal moderate risk exploration in a well-established, oil-producing fairway featuring multi-zone potential.

India

Bengal's onshore India block is situated within the Cauvery Basin (CY-ONN 2005/1 30% WI). The Company continues to coordinate with its partners, Gas Authority of India Ltd. ("GAIL") and Gujarat State Petroleum Corporation ("GSPC") for the drilling of three exploration wells. The wells are expected to be drilled by GAIL, the operator, during calendar 2014. The delays that the Company has experienced with respect to this project have stemmed from regulatory and permitting issues, which are aggressively being addressed by the operator. Bengal continues to work with its partners and the relevant government bodies to advance drilling.

The Company made wrote-down its offshore block in light of continued uncertainty regarding the future work plan and the inability to secure a joint interest partner to date. Bengal is engaged in discussions with the regulatory authorities as to how it might proceed if a partner is not found.

SUMMARY

With the recently announced signing of indicative term sheet with a leading Australian bank, the Company believes it is sufficiently capitalized to undertake its planned Cuisiner development plans and work program commitments and utilize internally generated cash flows and existing working capital to fund future planned exploration activities in India and Australia.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
Revenue						
Oil	**$ 5,174**	$ 2,946	76	**$ 19,480**	$ 5,669	244
Natural gas	**87**	67	30	**274**	172	59
Natural gas liquids	**11**	-	N/A	**68**	44	55
Total	**$ 5,272**	$ 3,013	75	**$ 19,822**	$ 5,885	237
Royalties	**407**	271	50	**1,334**	526	154
% of revenue	**7.7**	9.0	(14)	**6.7**	8.9	(25)
Operating & transportation	**1,496**	694	116	**5,290**	1,726	206
Operating netback[1]	**3,369**	$ 2,048	65	**13,198**	$ 3,633	263
Cash from (used in) operations:	**2,106**	119	1670	**7,591**	(703)	N/A
Per share ($) (basic & diluted)	**0.03**	(0.00)		**0.12**	(0.01)	N/A
Funds from (used in) operations:[2]	**2,218**	1,151	93	**8,183**	1,099	645
Per share ($) (basic & diluted)	**0.03**	0.02	50	**0.13**	0.02	550
Net (loss):	**(1,804)**	(592)	(205)	**150**	(1,799)	N/A
Per share ($) (basic & diluted)	**(0.03)**	(0.01)	200	**.00**	(0.03)	N/A
Capital expenditures	**2,048**	$ 1,280	60	**$ 16,647**	$ 28,381	(41)
Volumes						
Oil (bpd)	**472**	287	64	**433**	138	214
Natural gas (mcfd)	**180**	229	(21)	**201**	180	12
Natural gas liquids (boepd)	**2**	-	N/A	**2**	2	-
Total (boepd @ 6:1)	**504**	325	55	**468**	170	175
Netback[1] ($/boe)						
Revenue	**116.24**	$ 102.88	13	**$ 115.94**	$ 94.95	22
Royalties	**8.97**	9.25	(3)	**7.80**	8.49	(8)
Operating & transportation	**32.99**	23.70	39	**30.94**	27.85	11
Total	**74.28**	$ 69.93	6	**$ 77.20**	$ 58.61	32

(1) Operating 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 6.

Basis of Presentation

This MD&A and accompanying financial statements and notes are for the twelve months ended March 31, 2014 and 2013. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from January 1, 2014 through March 31, 2014. The terms "prior year's quarter" and "2013 quarter" are used throughout the MD&A for comparative purposes and refer to the period from January 1, 2013 through March 31, 2013.

The fiscal year for the Company is the twelve-month period ended March 31, 2014. The terms "fiscal 2014," "current year" and "the year" are used in the MD&A and in all cases refer to the period from April 1, 2013 through March 31, 2014. The terms "previous year," "prior year" and "fiscal 2013" are used in the MD&A for comparative purposes and refer to the period from April 1, 2013 through March 31, 2014. The term YTD means year-to-date.

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

The following abbreviations are used in this MD&A: boepd means barrels of oil equivalent per day; bpd means barrels per day; mcfd 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 March 31		Twelve Months Ended March 31	
$000s	**2014**	2013	**2014**	2013
Cash flow from (used in) operating activities	**2,106**	119	**7,591**	(703)
Changes in non-cash working capital	**112**	1,032	**592**	1,802
Funds from (used in) operations	**2,218**	1,151	**8,183**	1,099

RESULTS OF OPERATIONS - AUSTRALLIA

Production, Commodity Pricing and Sales

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

Production	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% change
Oil Production (bbls/d)	**504**	325	55	**468**	170	175
Realized oil prices ($/bbl)	**121.68**	114.02	8	**123.31**	112.84	9
Oil Sales	**5,174**	2,946	76	**19,480**	5,669	244

Oil sales in Australia are derived from its producing Cuisiner production license. Increased sales revenue for the both the quarter and year ended March 31, 2014 compared to the corresponding periods in 2014 was due to an increased production base and higher realized commodity prices.

Production

Production gains are attributed to the Cuisiner development programs which have continued to add production throughout fiscal 2014 as detailed below:

- The Cuisiner 1, 2 and 3 wells were offline for most of fiscal 2013 and were brought back on-stream in May of 2013, which added incremental production of approximately 36 bpd.
- Cuisiner 4, 5 and 6 were brought on-stream in October of 2012 adding an average of 94 bpd in fiscal 2013 compared to 201 bpd contributed to fiscal 2014 during which all of these wells were on-stream for the entire year.
- Production gains from the Company's 2013 drilling campaign were realized in July to December of 2013 when the Cuisinier 7 through 12 wells were brought on-stream adding incremental production of approximately 153 bpd for the five wells net to Bengal.
- 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).

Pricing

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 $6.34/bbl over Brent for the twelve months ended March 31, 2014 (2013 – USD $5.14).

Realized crude oil prices increased by 7% for the year and 9% for the quarter ended March 31, 2014 relative to the prior year and quarter despite a decrease to benchmark prices due to a significant increase in the value of the US dollar relative to the Canadian dollar. The Company's oil sales are based on a premium to Brent benchmark pricing denominated in US dollars.

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

Prices and Marketing	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
Average Benchmark Price						
Bengal realized crude oil price ($CAD/bbl)	**121.68**	114.02	7	**123.31**	112.84	9
Dated Brent oil ($CAD/bbl)[(1)]	**118.81**	112.43	6	**112.917**	110.03	3
Dated Brent oil ($US/bbl)	**108.14**	112.43	(4)	**107.54**	110.03	(2)
Number of CAD$ for 1 AUD$	**0.99**	1.05	(6)	**.98**	1.03	(5)
Number of CAD$ for 1 USD$	**1.10**	1.00	10	**1.05**	1.00	5

Royalties

Royalties ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
Royalty Expense	**396**	265	49	**1,305**	510	156
$/boe	**8.26**	9.25	(18)	**8.73**	8.49	(4)
% of revenue	**8**	9	(15)	**7**	9	(22)

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

Royalties have decreased in the quarter and year ended March 31, 2014 compared to the prior year and quarter both on a total dollar and on a boe basis due to the operating and transportation costs allowances, which has increased on a per boe basis by 6% and 28% for the year and quarter respectively.

Operating & Transportation Expenses

Operating Expenses ($000s)		**Three Months Ended March 31**			**Twelve Months Ended March 31**	
	2014	2013	% Change	**2014**	2013	% Change
Operating	**287**	92	212	**965**	516	87
Transportation	**1,135**	531	114	**4,084**	996	310
	1,422	623	128	**5,049**	1,512	234
Operating - $/boe	**6.75**	3.56	90	**6.11**	10.27	(41)
Transp. - $/boe	**26.69**	20.54	30	**25.85**	19.83	30
	33.44	24.10	39	**31.96**	30.10	6

The increase in operating and transportation costs for the current year and quarter were due primarily to increased production volumes.

Operating costs per barrel stabilized during the year which resulted in an increase of 90% for Q4 2014 compared to the prior year and a decrease of 41% for the 2014 fiscal year compared to the previous year. Development and appraisal drilling has continued to develop the Cuisinier field which was awarded a production license during fiscal 2014. This has resulted in increasing operator's charges for enhanced field operations, which are partially offset by increasing production.

Transportation costs on a boe basis have increased from prior period due to commissioning of the Cuisinier to Cook pipeline and subsequent connection of this line to the Cook facility and the Cook to Merrimelia pipeline, connecting Cuisinier oil from wellhead to tanker to ensure deliverability. The pipeline costs are marginally higher than costs incurred previously to truck the oil; however this ensures continuous deliverability.

RESULTS OF OPERATIONS - CANADA

Canadian Operating Results		**Three Months Ended March 31**			**Twelve Months Ended March 31**	
	2014	2013	% Change	**2014**	**2013**	% change
Natural Gas Sales	**87**	67	30	**274**	172	59
Production(mcf/d)	**180**	229	(21)	**201**	180	12
Realized commodity prices ($/mcf)	**5.38**	3.25	66	**3.74**	2.61	43
NGL Sales	**11**	-	N/A	**68**	44	55
Production(bbl/d)	**2**	-	N/A	**2**	2	-
Realized commodity prices ($/bbl)	**79.14**	-	N/A	**87.29**	57.37	52
Royalties	**11**	6	**83**	**29**	16	81
($/boe)	**2.21**	1.37	**61**	**3.82**	1.75	118
Operating Expenses	**71**	71	**-**	**241**	214	13
($/boe)	**18.56**	18.22	**2**	**26.13**	20.69	26
Operating Netback	**16**	(10)	**N/A**	**72**	(14)	N/A
($/boe)	**5.56**	(2.92)	**N/A**	**5.48**	(1.20)	N/A

Canadian operations are comprised entirely of the Company's non-operated Oak natural gas field in British Columbia. This asset is considered non-core and therefore no significant expenditures were allocated to the Oak field in fiscal 2014, however increased benchmark natural gas prices resulted in marginal profitability for the asset.

General and Administrative (G&A) Expenses and Share Based Compensation ("SBC")

General and Admin. Expenses ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
G&A - cash	**1,579**	863	83	**3,964**	3,356	18
Share based Compensation	**119**	173	(31)	**650**	687	(5)
Total G&A	**1,698**	1,036	64	**4,614**	4,043	14
Capitalized G&A	**130**	120	8	**421**	504	(16)
Capitalized SBC	**101**	127	(20)	**509**	487	5

The 18% increase in cash G&A expenditures for the year and part of the quarterly increase, reflects increased overhead costs required to manage the Company's growing exploration and production portfolios. For the quarter, cash G&A expenses increased $83% due to expansion, the timing of hiring and salary increase and consulting fees recognized in the fourth quarter of 2014.

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. The decrease in share-based compensation expense reflects a lower calculated value per option averaged for the year and the quarter ended March 31, 2014.

Transaction costs of $261,000 (2013 – nil) were incurred during fiscal 2014 relating to the execution of the Farm-in agreement at ATP 732.

Depletion and Depreciation (DD&A)

DD&A Expenses ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
PNG – Australia	**1,253**	708	77	**4,434**	1,255	253
PNG – Canada	**21**	30	(30)	**97**	120	(19)
Total	**1,274**	738	73	**4,531**	1,375	230
$/boe – PNG Australia	**29.47**	27.38	8	**28.07**	24.98	12
$/boe – PNG Canada	**7.42**	8.75	(15)	**7.47**	10.22	(27)
$/boe – Total PNG	**28.09**	25.20	11	**26.50**	22.18	19

Depletion per boe increased in Australia due to increases in petroleum and natural gas properties and future development costs associated with proved and probable reserves at March 31, 2014.

The drilling rig was not utilized in the current quarter and therefore there is no depreciation charge.

Impairment

Impairment ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	**% Change**	**2014**	2013	% Change
	2,111	829	155	**3,101**	81	3728

At March 31, 2014, the Company's wholly owned Ideco H-44 drilling rig was idle for more than 12 months, which has been identified as a trigger for impairment. The Company estimated the recoverable amount of $3.5 million based on a fair value less costs-to-sell methodology using recent market transactions as a fair value estimate. As a result, the Company recognized a $1.9 million impairment charge during Q4 2014 related to the drilling rig.

The off-shore India permit, CY-OSN2009/1 is scheduled to expire on August 15, 2014. Management has no capital allocated to this asset in its current budget and has not been successful in attracting a partner to share exploration costs, therefore an impairment to exploration and evaluation assets of $1.2 million, which represents the entire carrying value of this assets and, in addition, a provision for expected costs of relinquishment, has been recorded.

Finance Income

Finance Income ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	**% Change**	**2014**	2013	% Change
	5	2	150	**74**	167	(56)

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 March 31			Twelve Months Ended December 31		
	2014	2013	% Change	**2014**	2013	% Change
Accretion expense on decommissioning liabilities	**(3)**	2	(250)	**(13)**	7	(286)
Accretion expense on notes	**52**	59	(12)	**217**	59	268
Accretion of VARs	**(64)**	-	N/A	**(123)**	-	N/A
Guarantee fee	**71**	16	344	**71**	43	65
Interest on notes payable	**241**	38	534	**777**	38	1945
Finance expenses	**297**	115	158	**929**	147	532

The Performance Security Guarantee fee is paid to Export Development Canada and ICICI Bank of India for security guarantee for onshore and offshore India work programs, to be cancelled on completion or relinquishment. The increased fee is a result of the budgeted 2014 work program.

Interest on notes and accretion expense relate to the amortization of the discount on the $3.5 million convertible and non-convertible notes issued in January 2013 and the $8.0 million note issued in July of 2013.

CAPITAL EXPENDITURES

Capital Expenditures ($000s)	Three Months Ended March 31			Twelve Months Ended March 31		
	2014	2013	% Change	**2014**	2013	% Change
Geological and geophysical	**$ 708**	$ 190	273	**$ 3,137**	$ 4,232	(26)
Drilling	**389**	672	(42)	**2,601**	15,595	(83)
Drilling Rig	**371**	23	N/A	**371**	4,511	(92)
Completions	**376**	395	359	**3,574**	4,023	(11)
Acquisitions	**204**	-	N/A	**6,964**	-	N/A
Total oil & gas expenditures	**2,048**	1,280	117	**16,647**	28,361	(41)
Office	**-**	-	-	**-**	19	N/A
Total expenditures	**$ 2,048**	$ 1,280	117	**$ 16,647**	$ 28,380	(41)
Exploration & evaluation Expenditures	**$ 672**	$ 303	121	**$ 1,963**	$ 16,017	(88)
Development & production Expenditures	**1,005**	954	5	**14,313**	7,853	82
Property, plant and equipment	**371**	23	1513	**371**	4,511	(92)
Total net expenditures	**$ 2,048**	$ 1,280	60	**$ 16,647**	$ 28,381	(41)

During the year, the Indian seismic program was completed culminating in the selection of three drilling locations expected to begin drilling in 2014. Geological and geophysical costs also include participation in the Cuisinier North 3D seismic survey and ongoing seismic interpretation instrumental in selection two exploration locations expected to be drilled in Cuisinier during 2014.

During fiscal 2014, Cuisinier drilling and completion operations relating to the prior year's program were finalized and preliminary work was performed in preparation for Phase One of the 2014 Cuisinier drilling program, which commenced near the end of March 2014.

In December of 2013, the Company completed the acquisition of additional working interest in production oil assets located in Cuisinier (Part of the Barta block in Australia).

CONVERTIBLE AND NON-CONVERTIBLE NOTES

The Company issued $1,750,000 in convertible notes and $1,750,000 in non-convertible notes in January 2013 for a term of 180 days. The convertible notes were converted / repaid in July 2013 as further described in the Related Party section on page 13. The interest rate was prime plus 3% through July 2013. The non-convertible notes were extended to January 24, 2014 at a rate of 10%.

On July 5, the Company issued $8,000,000 of 10% non-convertible notes with warrants or value appreciation rights. Each unit consists of $1,000 principal amount of 10% unsecured non-convertible redeemable notes and either: (i) 156.25 common share purchase warrants, in the case of subscriptions by non-insiders, or (ii) 156.25 value appreciation rights ("VARs"), in the case of subscriptions by insiders. The notes bear interest at a rate of 10% per annum, payable quarterly, and have a term of 36 months. Following the first anniversary of the closing date of the private placement, the Company shall be required to make quarterly repayments of the outstanding principal of Notes in an amount equal to 6.25% of the principal amount of notes outstanding on the last day of each applicable quarter. Each whole warrant entitles the holder thereof, for a period of 36 months following the closing date, to acquire one common share in the capital of the Company at a purchase price equal to $0.75 per share. Each whole VAR entitles the holder thereof, for a period of 36 months following the closing date, to exercise the VAR and thereby receive a cash payment equal to the difference between the market price of one common share on the exercise date and $0.75. Certain insiders of the Company purchased 3,500 Units and received 546,875 VARs, and 4,500 Units were purchased by non-insiders who received 703,125 warrants.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. At June 16, 2014, there were 64,692,082 common shares issued and outstanding.

At June 13, 2014, there were 3,623,334 employee stock options outstanding with an average exercise price of $0.89 per share. Of these, 2,486,672 have vested and are exercisable at an average price of $1.04 per share. These options expire between June 2016 and January 22, 2019 with an average remaining life of 3.2 years.

Trading History			**Three Months Ended March 31**			**Twelve Months Ended March 31**
	2014	2013	% Change	**2014**	2013	% Change
High	**0.62**	0.80	(23)	**0.79**	1.09	(28)
Low	**0.40**	0.50	(20)	**0.40**	0.49	(18)
Close	**0.48**	0.70	(31)	**0.48**	0.70	(31)
Volume (000s)	**6,621**	3,560	86	**10,323**	18,932	(45)
Shares outstanding (000s)						
Basic and diluted	**64,667**	52,110	22	**64,667**	52,110	22
Weighted average shares outstanding (000s)						
Basic	**63,446**	52,110	22	**63,134**	52,110	22
Diluted	**63,446**	52,110	22	**63,209**	52,110	22

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2014 the Company had 3.1 million of working capital, including cash and short-term deposits of $6.0 million and restricted cash of $0.1 million, compared to a working capital deficit of $1.6 million, including cash and short term deposits of $2.6 million and restricted cash of $0.1 million at March 31, 2013.

Subsequent to year-end, Bengal signed an indicative term sheet for a US $20.0 million secured credit facility with a leading Australian commercial bank. Once finalized the facility is expected to fully fund Bengal's Australian development through March 2015; allowing the Company to fund future planned exploration activities in India and Australia with internally generated cash flows. In the unlikely event that this facility is not closed within its expected timeframe, the Company may need to seek additional sources for financing including other sources of debt, equity or effective dilution of its joint venture interests.

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 supplemented by funds expected upon closing of a secured credit facility are expected to be sufficient to meet all of its working capital requirements for at least the next twelve months and its commitments under its capital program (see Commitments below).

The Company expects cash generation to increase throughout the coming year as production from Cuisinier ramps up, although predicting future events, some of which are beyond the Company's control, carries uncertainty.

COMMITMENTS

Pursuant to current production sharing contracts ("PSC"), the Company is required to perform minimum exploration activities in its Indian permits that include various types of surveys, acquisition and processing of seismic data and drilling of exploration wells. Additional commitments are reflected where the Company has agreed with joint venture partners to proceed with activities (e.g. onshore Australia ATP 752 Cuisinier). The costs of these activities are based on minimum work budgets included in bid documents and agreements among joint venture parties, and have not been provided for in the financial statements. Actual costs will vary from budget.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Cuisinier (ATP 752 – Barta permit)	Two well exploration program	September 30, 2014	$1.7
Onshore India – CY-ONN-2005/1	3 wells	March 3, 2014(2)	$ 4.2
Offshore India – CY-OSN-2009/1(3)	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$ 5.3

(1) Translated at March 31, 2014 at an exchange rate of US $1.0000 = CAD $1.10; AUS $1.00 = CAD $1.02
(2) If the Company did not participate in the drilling of 3 wells, costs of $5.2 million would be impaired and the Company's interest in the permit would decline.
(3) The Company expects to relinquish this permit on or before its expiry date, resulting in an impairment of 100% of the asset's carrying value and a provision for expected penalties.

GUARANTEES – INDIA PERMITS

($000s) CAD	Year Ended March 31, 2014	Year ended March 31, 2013
CY-OSN-2005/1 – Onshore India	**1,570**	**735**
CY-OSN-2009/1 – Offshore India	**166**	**154**
Total Guarantees	**$ 1,736**	**$ 889**

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.

<u>Other</u>

At March 31, 2014, 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	$ 775	$ 258	$ 517	$ -	$ –
Decommissioning obligations	358	-	-	–	358
Total contractual obligations	$ 1,170	$ 258	$ 517	$ 63	$ 358

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 kilometers 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	$ 12.4

RELATED PARTY TRANSACTIONS

On July 5, the Company issued $8.0 million of 10% non-convertible notes with warrants or value appreciation rights. Members of the Board of Directors of the Company subscribed for approximately 86% of the principal amount of the notes issued pursuant to the Private Placement.

On January 24, 2014 the Company extended its $1.8 million note payable to January 23, 2015. Members of the Board of Directors of the Company hold 100% of this facility.

SUBSEQUENT EVENTS

On May 27, 2014 Bengal announced it had entered into an indicative term sheet for a US $20.0 million secured credit facility (the "Facility") with a leading Australian commercial bank (the "Lender"). The Facility contemplates a borrowing base of up to US $20 million, over a three year term at attractive fixed income market rates tied to USD LIBOR to fund its ongoing Australian development. The Facility remains subject to the completion of due diligence by the Lender and the entering into of a final Offer to Finance with Bengal and will remain open for a fixed period to allow Bengal to review other competitive lending proposals that may be received.

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED ANNUAL FINANCIAL INFORMATION

($000s except per share data and prices)

Year Ended March 31	**2014**	2013	2012
Total production volumes (boepd)	**468**	170	135
Natural gas prices ($/mcf)	**3.74**	2.61	3.33
Oil and liquids prices ($/boe)	**123.13**	112.01	117.41
Total production revenue	**19,822**	5,885	4,286
Net income (loss)	**150**	(1,799)	(7,209)
Per share – basic and diluted	**0.00**	(0.03)	(0.14)
Cash from operations	**7,591**	(703)	(1,142)
Per share – basic and diluted	**0.12**	(0.01)	(0.02)
Funds from operations (1)	**8,183**	1,099	(1,459)
Per share – basic and diluted	**0.13**	0.02	(0.03)
Notes payable – long term	**6,085**	-	-
Total assets	**62,425**	49,143	43,696
Working capital (deficiency)(2)	**3,104**	(1,647)	25,722

(1) See "Non-IFRS Measurements" on page 6 of this MD&A.
(2) Calculated as current assets minus current liabilities.
(3) The Company has no non-current financial liabilities.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)

	Mar 31 2014	Dec. 31 2013	Sep. 30 2013	Jun. 30 2013	Mar 31 2013	Dec. 31 2012	Sep. 30 2012	Jun. 30 2012
Petroleum and natural gas sales	**$5,272**	$ 5,516	$ 5,312	$ 3,722	$ 3,013	$ 1,937	$ 437	$ 498
Cash from (used in) operations	**2,106**	2,170	2,066	1,249	119	(378)	315	(759)
Per share Basic and diluted	0.03	0.03	0.03	0.02	(0.00)	(0.01)	0.01	(0.01)
Funds from (used in) operations[1]	***2,218***	2,862	2,063	1,732	1,151	481	(471)	(62)
Per share Basic and diluted	**0.03**	0.04	0.03	0.03	0.02	0.01	(0.01)	0.00
Net (loss) income	**(1,804)**	573	$ 545	$ 836	$ (592)	$ (151)	$ (845)	$ (211)
Per share Basic and diluted	**(0.03)**	0.01	0.01	0.01	(0.01)	(0.00)	(0.02)	0.00
Capital expenditures	**2,048**	$6,462	$ 2,702	$ 5,435	$ 1,281	$ 9,475	$ 10,299	$ 7,326
Working capital (deficiency)	**3,104**	3,590	7,737	(279)	(1,647)	(1,436)	7,578	
Total assets	**62,425**	61,353	62,361	54,556	49,143	47,584	46,557	18,425
Shares outstanding Basic and diluted	**64,446**	64,315	64,315	61,611	52,110	52,110	52,110	52,110
Operations								
Average daily production								
Natural gas (mcfd)	**180**	184	200	240	229	110	159	225
Oil and NGLs (bbls/d)	**474**	465	485	316	287	185	38	51
Combined (boepd)	**504**	496	518	356	325	203	65	89
Netback ($/boe)	**74.28**	$ 83.13	$ 72.51	$ 79.82	$ 69.93	$ 60.92	$ 40.07	$ 24.

(1) See "Non-IFRS Measurements" on page 7 of this MD&A. The bottom line of this table pops out showing a hefty decline in netback from the December quarter perhaps we should explain this in the text.

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 wells were drilled in mid 2012 and started producing under a six month Extended Production Test in October 2012. The Cuisinier 1, 2 and 3 wells came back onto production in May 2013 after approval of the Production License. Production started from Cuisinier 7, 8 and 10 in July 2013 and from Cuisinier 9 and 11 in August 2013 contributing to production increases. In December of 2013, the Company finalized the acquisition of an additional 5% interest in the Cuisinier license and this increased production share offset natural declines through March 2014.

The decrease in netbacks from the fiscal third to fourth quarter of 2014 are due primarily to decreased benchmark crude prices and an increase in the value of the Australian vs. Canadian dollar in which the Company pays the majority of its royalties and operating costs.

FINANCIAL INSTRUMENTS

Financial instruments comprise cash, restricted cash and short term deposits, accounts receivable and accounts payable and accrued liabilities. The fair values of these financial instruments approximate their carrying amounts due to their short-term maturities.

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company does not use derivative instruments at this time.

Financial assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss ("FVTPL"), loans and receivables, held to maturity investments, available for sale financial assets, or other liabilities, as appropriate. Financial assets and liabilities are recognized initially at fair value.

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

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

i. Non-derivative financial instruments

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

ii. Derivative financial instruments

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

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

Fair value

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

Share capital

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

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were not effective at March 31, 2013 due to the material weaknesses noted below.

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

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

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

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

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of

Directors work to mitigate the risk of material misstatement; however, Management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company’s accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

iii. Identification of Cash-generating Units

Bengal’s assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

iv. Impairment Indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The application of the Company’s accounting policy for exploration and evaluation, petroleum and natural gas properties and PP&E assets required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Key Sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of the assets and liabilities.

i) Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

ii) Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of assets, and impairment charges and reversal will affect profit or loss.

iii) Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period which the change occurs.

iv) Reserves

The estimate of petroleum and natural gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's development and production assets has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

v) Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

NEW ACCOUNTING STANDARDS AND PRONOUNCEMENTS

On April 1, 2013, the Company adopted the following new standards that were effective for annual periods beginning on or after January 1, 2013. The adoption of these standards resulted in certain additional disclosure but otherwise had no impact on the amounts recorded in the financial statements as at March 31, 2014 or on the comparative periods.

IFRS 10 – Consolidated Financial Statements, IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. IFRS 10 replaces SIC-12 Consolidation – Special Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements.

IFRS 11 – Joint Arrangements. IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or a joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation a venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities – Non-Monetary Contributions by Venturers.

IFRS 12 – Disclosure of Interests in Other Entities. IFRS 12 applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity.

IFRS 13 – Fair Value Measurements. IFRS 13 defines fair value, sets out a single IFRS framework for measuring value and requires disclosure about fair value measurements. IFRS 13 applies to IFRS's that require or permit fair value measurements or disclosures about fair value measurement, except in specified circumstances.

New standards and interpretations not yet adopted:

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

IFRS 9 – Financial Instruments. IFRS 9 covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. The effective date for IFRS 9 has been deferred. Early adoption will still be available and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting this new standard

IFRIC 21 - Interpretation of IAS 37 Provisions, contingent liabilities and assets. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event. The interpretation clarifies that the obligation that gives rise to the liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. The Company is currently evaluating the impact of this standard.

RISK FACTORS

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

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

Exploration, Development and Production Risks

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

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

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

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

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

Risks Associated with Foreign Operations

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

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

Substantial Capital Requirements and Liquidity

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

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

Health, Safety and Environment

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

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

Insurance

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

Competition

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

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

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 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;*
- *Expectations that cash generation to increase throughout the coming year*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Completion of the four development wells is anticipated to run from mid-July through early August 2014, with the wells expected to be tied in through September 2014.*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Expectations that cash flow from the new production volumes to begin in the fourth quarter of calendar 2014;*
- *Expectation of the drilling of a exploration at ATP 752 well in calendar Q3 2014;*
- *Obtaining Ministerial Grant of the tenement on ATP 934P in Australia and commencement of exploration activities;*
- *Expectation that the selection of three drilling locations in India expected to begin drilling in 2015*
- *That Beach Energy will perform the work agreed to under the Farm-out and that further drilling activities on ATP 732P will occur in the second half of calendar 2014;*
- *That the wells drilled on ATP 752P will be completed and tied-in and that these wells will commence production and that production from all wells will continue as expected.*

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.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The accompanying consolidated financial statements are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards outlined in the notes to the consolidated financial statements. The consolidated financial statements include certain estimates that reflect the management's best judgments. Management has determined such amounts on a reasonable basis in order to ensure that the consolidated financial statements are presented fairly, in all material respects. In the opinion of management, the consolidated financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards. The financial information contained in the annual report is consistent with that in the consolidated financial statements.

Management is also responsible for establishing and maintaining appropriate systems of internal control over the company's financial reporting. The internal control system was designed to provide reasonable assurance to management regarding the preparation and presentation of the consolidated financial statements. Management tested and evaluated the effectiveness of its disclosure controls and procedures and internal controls over financial reporting as at March 31, 2014. During this evaluation Management identified weaknesses due to the limited number of finance and accounting personnel at the Corporation dealing with complex and non-routine accounting transactions that may arise and due to a lack of segregation of duties and as a result the controls are not considered effective. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable but not absolute assurance that financial information is accurate and complete.

KPMG LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent annual general meeting, to examine the consolidated financial statements in accordance with Canadian generally accepted auditing standards and provide an independent professional opinion.

The audit committee of the Board of Directors with all of its members being independent directors, have reviewed the consolidated financial statements including notes thereto with management and KPMG LLP. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

(signed) " Chayan Chakrabarty"
Chayan Chakrabarty
President & Chief Executive Officer

(signed) " Jerrad Blanchard"
Jerrad Blanchard
Chief Financial Officer

To the Shareholders of Bengal Energy Ltd.

We have audited the accompanying consolidated financial statements of Bengal Energy Ltd., which comprise the consolidated statements of financial position as at March 31, 2014 and March 31, 2013, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Bengal Energy Ltd. as at March 31, 2014 and March 31, 2013, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
June 13, 2014
Calgary, Canada

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at March 31,	Notes	2014	2013
ASSETS			
Current assets:			
Cash and cash equivalents	5	$ 5,984	$ 2,614
Restricted cash		140	140
Accounts receivable		3,821	3,550
Prepaid expenses and deposits		490	110
		10,435	6,414
Non-current assets:			
Exploration and evaluation assets	6	26,821	26,416
Petroleum and natural gas properties	7	21,669	11,630
Property, plant and equipment	8	3,500	4,683
		51,990	42,729
Total assets		$ 62,425	$ 49,143
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued liabilities		$ 4,174	$ 4,622
Current portion of notes payable	10	3,158	3,439
		7,332	8,061
Non-current liabilities:			
Decommissioning liability	11	358	320
Notes payable	10	6,085	-
Other long-term liabilities	10	61	-
		6,504	320
Shareholders' equity:			
Share capital	12	93,151	86,246
Contributed surplus		7,141	6,466
Warrants	10	167	-
Equity component convertible debenture	10	-	25
Accumulated other comprehensive income		1,536	1,581
Deficit		(53,406)	(53,556)
		48,589	40,762
Total liabilities and shareholders' equity		$ 62,425	$ 49,143

Commitments and contingencies (note 18)

Subsequent event (note 21)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Chayan Chakrabarty

Director
Chayan Chakrabarty

Director
James B. Howe

BENGAL ENERGY LTD.

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

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2014	2013
Income			
Petroleum and natural gas revenue		19,822	5,885
Royalties		(1,334)	(526)
		18,488	5,359
Operating expenses			
General and administrative		3,822	3,466
Transaction costs		261	-
Operating and transportation		5,290	1,726
Depletion and depreciation	7,8	4,531	1,448
Pre-licensing & impairment	6,8	3,101	80
Share-based compensation		498	487
		17,503	7,207
Operating income (loss)		985	(1,848)
Other income (expenses)			
Finance income		74	167
Finance expenses	14	(929)	(133)
Foreign exchange (loss) gain		(35)	7
		(890)	41
Net income (loss) before income tax		95	(1,807)
Deferred income tax recovery	9	55	8
Net income (loss)		150	(1,799)
Exchange differences on translation of foreign operations		(45)	864
Total comprehensive income (loss) for the year		105	(935)
Earnings (loss) per share	12		
- Basic & Diluted		0.00	(0.03)
Weighted average number of shares outstanding (000s)	12		
- Basic		63,134	52,110
- Diluted		63,209	52,110

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

	Shares outstanding	Share capital	Warrants	Contributed surplus	Equity component of convertible debentures	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2012	**52,110,177**	**$ 86,246**	**$ –**	**$ 5,779**	**$ –**	**$ 717**	**$ (51,757)**	**$ 40,985**
Net loss for the year	**-**	**-**	**-**	**-**	**-**	**-**	**(1,799)**	**(1,799)**
Comprehensive income for the year	**-**	**-**	**-**	**-**	**-**	**864**		**864**
Share-based compensation – expensed	**-**	**-**	**-**	**487**	**-**	**-**	**-**	**487**
Share-based compensation – capitalized	**-**	**-**	**-**	**200**	**-**	**-**	**-**	**200**
Convertible notes issued	**-**	**-**	**-**	**-**	**25**	**-**	**-**	**25**
Balance at March 31, 2013	**52,110,177**	**$ 86,246**	**$ –**	**$ 6,466**	**$ 25**	**$ 1,581**	**$ (53,556)**	**$ 40,762**
Balance at April 1, 2013	**52,110,177**	**$ 86,246**	**$ –**	**$ 6,466**	**$ 25**	**$ 1,581**	**$ (53,556)**	**$ 40,762**
Net loss for the year							150	**150**
Comprehensive income (loss) for the year						(45)		**(45)**
Issuance of common shares	12,556,905	7,327						**7,327**
Share issue costs		(422)						**(422)**
Share-based compensation – expensed				498				**498**
Share-based compensation – capitalized				152				**152**
Warrants			167	25	(25)			**167**
Balance at March 31, 2014	**64,667,082**	**93,151**	**167**	**7,141**	**-**	**1,536**	**53,406**	**48,589**

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the years ended March 31	Notes	2014	2013
Operating activities			
Net income (loss) for the year		$ 150	$ (1,799)
Non-cash items:			
Depletion and depreciation		4,531	1,448
Pre-licensing & impairment		3,101	927
Accretion on decommissioning liability		(8)	7
Accretion on note payable		93	45
Share-based compensation		498	487
Deferred income tax recovery		(55)	(8)
Unrealized foreign exchange gain		(127)	(8)
		8,183	1,099
Change in non-cash working capital	17	(592)	(1,802)
Net cash from (used in) operating activities		7,591	(703)
Investing activities			
Exploration and evaluation expenditures		(1,963)	(16,017)
Petroleum and natural gas properties		(14,313)	(7,853)
Property, plant and equipment		(371)	(4,511)
Change in restricted cash		-	(5)
Changes in non-cash working capital	17	(808)	1,107
Net cash used in investing activities		(17,455)	(27,279)
Financing activities			
Proceeds from issuance of shares, net of issuance costs	12	5,405	–
Proceeds from issuance of debt, net of issuance costs	10	7,743	3,461
Repayment of convertible debt	10	(250)	-
Changes in non-cash working capital	17	(5)	38
Net cash from financing activities		12,893	3,499
Impact of foreign exchange on cash and cash equivalents		341	163
Net increase (decrease) in cash equivalents		$ 3,370	$ (24,320)
Cash and cash equivalents, beginning of year		2,614	26,934
Cash and cash equivalents, end of year		$ 5,984	$ 2,614

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements (the “financial statements”)

Years ended March 31, 2014 and 2013
(Tabular amounts are stated in thousands of Canadian dollars except share and per share amounts)

1. REPORTING ENTITY:

Bengal Energy Ltd (the “Company” or “Bengal”) is incorporated under the laws of the Province of Alberta and is involved in the exploration for and development and production of oil and gas reserves in Australia, India and Canada. The consolidated financial statements (the “financial statements”) of the Company as at March 31, 2014 and 2013 and for the years ended March 31, 2014 and 2013 are comprised of the Company and its wholly owned subsidiaries Bengal Energy International Inc., Bengal Energy Australia (Pty) Ltd., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. respectively 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

a) Statement of compliance

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

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on June 13, 2014.

b) Basis of measurement

These consolidated financial statements have been prepared on a historical cost basis.

c) Functional and presentation currency

The Company’s presentation currency is Canadian dollars ($). The functional currency of the Canadian parent entity is Canadian dollars, the functional currency of the India subsidiary is U.S. dollars and the functional currency of the Australian subsidiary is Australian dollars.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

(a) Basis of consolidation:

The consolidated interim financial statements incorporate the financial statements of the Company and its wholly and majority owned subsidiaries, Bengal Energy Australia (Pty) Ltd., Bengal Energy International Inc., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. respectively.

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain the benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

The Company recognizes in its financial statements its proportionate share of the assets, liabilities, revenues, and expenses of its joint operations.

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

(b) Cash and cash equivalents

Cash and cash equivalents include cash and all investments with a maturity of three months or less.

(c) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax "risk-free" rate that reflects current market assessments of the time value of money and the risks specific to the liability. The unwinding of the discount is recognized as a finance expense. Provisions are not recognized for future operating losses.

Decommissioning and restoration liabilities:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the period end date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

(d) Oil and natural gas exploration and evaluation expenditures

Exploration and evaluation costs ("E&E" assets")

All costs incurred prior to obtaining the legal right to explore an area are expensed when incurred.

Generally, costs directly associated with the exploration and evaluation of crude oil and natural gas reserves are initially capitalized. Exploration and evaluation costs are those expenditures for an area where technical feasibility and commercial viability has not yet been demonstrated. These costs generally include unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, drilling and completion costs and capitalized decommissioning costs.

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

(e) Petroleum and natural gas properties

Carrying value

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

Subsequent costs

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

Depletion and depreciation

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

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

(f) Property and equipment – drilling rig

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.

(g) Impairment

E&E and Petroleum and Natural Gas Properties

E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to Development and

Production ("D&P") assets. For the purpose of impairment testing, E&E assets are grouped by concession or field with other E&E assets belonging to the same concession or field. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit or loss. Recoverable amount is determined as the higher of the value in use or fair value less costs to sell.

At the end of each reporting period, the Company reviews the petroleum and natural gas properties for circumstances that indicate that the assets may be impaired. Assets are grouped together into CGUs for the purpose of impairment testing, which is the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGUs recoverable amount is the higher of its fair value less selling costs and its value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of future cash flows expected to be derived from the production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate, which would be applied by such a market participant to arrive at a net present value of the CGU. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down. Consideration is given to acquisition metrics or recent transactions completed on similar assets to those contained with the relevant CGU.

When the recoverable amount is less than the carrying amount, the asset or CGU is impaired. For impairment losses identified based on a CGU, the loss is allocated on a pro rata basis to the assets within the CGU(s). The impairment loss is recognized as an expense in profit or loss.

At the end of each subsequent reporting period these impairments are assessed for indicators of reversal. Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss have been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

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

Property and Equipment

At the end of each reporting period, the Company reviews property and equipment for circumstances that indicate that the assets may be impaired. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount, which is the higher of its fair value less selling costs and its value in use.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of an asset in an arm's length transaction between knowledgeable and willing parties. Consideration is given to recent transactions related to similar assets.

When the recoverable amount is less than the carrying amount, the asset is impaired and the resulting impairment loss is recognized as an expense in profit or loss.

At the end of each subsequent reporting period these impairments are assessed for indicators of reversal. Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss have been recognized for the asset in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(h) Financial instruments

Financial assets and liabilities are classified as either financial assets or liabilities at fair value through profit and loss (“FVTPL”), loans and receivables, held to maturity investments, available for sale financial assets, or other liabilities, as appropriate. Financial assets and liabilities are recognized initially at fair value.

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

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

(i) Non-derivative financial instruments

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

(ii) Derivative financial instruments

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

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

Fair value

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

Share capital

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

(i) Foreign currency translation:

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

(j) Share-based compensation:

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

(k) Revenue recognition:

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

(l) Per share amounts:

Basic per share amounts are computed by dividing net income (loss) by the weighted average number of common shares outstanding for the period. Diluted per share amounts are calculated giving effect to the potential dilution that would occur if stock options or other dilutive instruments were exercised into common shares. The treasury stock method assumes that any proceeds upon the exercise of dilutive instruments, including remaining unamortized compensation costs, would be used to purchase common shares at the average market price of the common shares during the period.

(m) Income taxes:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustments to tax payable in respect of previous years.

Deferred tax is recognized providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(n) Finance income and expenses:

Finance income consists of interest earned on term deposits. Finance expenses include fees on Performance Security Guarantees issued by Export Development Canada, bank fees on Bank Guarantees issued to the Government of India and accretion of the discount on decommissioning obligations.

(o) Determination of fair value:

A number of the Company's accounting policies and disclosures required the determination of fair value, both for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

1) The fair value of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2014 and March 31, 2013 the fair value of these balances approximated their carrying value due to their short term to maturity.

2) The fair value of employee stock options, warrants, and value appreciation rights are measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

3) The fair value of notes payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2014 and March 31, 2013 the fair value of these balances approximated their carrying value due to their short term to maturity

(p) Adoption of new accounting policies

On April 1, 2013, the Company adopted the following new standards that were effective for annual periods beginning on or after January 1, 2013. The adoption of these standards resulted in certain additional disclosure but otherwise had no impact on the amounts recorded in the financial statements as at March 31, 2014 or on the comparative periods.

IFRS 10 – Consolidated Financial Statements, IFRS 10 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. IFRS 10 replaces SIC-12 Consolidation – Special Purpose Entities and parts of IAS 27 Consolidated and Separate Financial Statements.

IFRS 11 – Joint Arrangements. IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or a joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation a venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. IFRS 11 supersedes IAS 31 Interests in Joint Ventures and SIC-13 Jointly Controlled Entities – Non-Monetary Contributions by Ventures.

IFRS 12 – Disclosure of Interests in Other Entities. IFRS 12 applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity.

IFRS 13 – Fair Value Measurements. IFRS 13 defines fair value, sets out a single IFRS framework for measuring value and requires disclosure about fair value measurements. IFRS 13 applies to IFRS's that require or permit fair value measurements or disclosures about fair value measurement, except in specified circumstances.

(q) New standards and interpretations not yet adopted:

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

IFRS 9 – Financial Instruments. IFRS 9 covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. The effective date for IFRS 9 has been deferred. Early adoption will still be available and the standard is required to be applied retrospectively. The Company is currently evaluating the impact of adopting this new standard

IFRIC 21 - Interpretation of IAS 37 Provisions, contingent liabilities and assets. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event. The interpretation clarifies that the obligation that gives rise to the liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. The Company is currently evaluating the impact of this standard.

4. MANAGEMENT JUDGMENTS AND ESTIMATES

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are out-lined below.

Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

i) Identification of Cash-generating Units

Bengal's assets are aggregated into cash-generating units, for the purpose of calculating impairment, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

ii) Impairment Indicators

Judgments are required to assess when impairment indicators exist and impairment testing is required. The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties and PP&E assets required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

Key Sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of the assets and liabilities.

i) Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

ii) Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets occurred, and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are future petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amount of assets, and impairment charges and reversal will affect profit or loss.

iii) Current and Deferred Income taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods. Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period which the change occurs.

Judgments are made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable earnings.

The deferred tax asset is based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates and the likelihood of assets being realized.

iv) Reserves

The estimate of petroleum and natural gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company’s development and production assets has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company’s reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators’ National Instrument 51-101. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

v) Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

5. CASH AND CASH EQUIVALENTS

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

As at ($000s)	March 31, 2014	March 31, 2013
Cash and bank balances	$ 5,164	$ 2,614
Short-term deposits	820	-
	$ 5,984	$ 2,614

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

($000s)		**Exploration and Evaluation Expenditures**
Balance at April 1, 2012	$	10,526
Additions		16,017
Capitalized share based compensation		166
E&E impairment loss		(927)
Exchange adjustments		634
Balance at March 31, 2013	**$**	**26,416**
Additions		1,963
Capitalized share based compensation		59
E&E impairment loss		(1,367)
Exchange adjustments		(250)
Balance at March 31, 2014		**26,821**

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 off-shore India permit, CY-OSN2009/1 is scheduled to expire on August 15, 2014. Management has no capital allocated to this asset and has not been successful in attracting a partner to share exploration costs, therefore an impairment to exploration and evaluation assets of $1.0 million, which represents the entire carrying value of this assets and a provision for expected costs of relinquishment, has been recorded.

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

	Exploration and Evaluation Assets		
($000s)	**Australia**	**India**	**Total**
ATP 732P – Tookoonooka **– Note 1**	$ 19,385	$ -	$ 19,385
CY-ONN-2005/1 – onshore	-	4,312	4,312
CY-OSN-2009/1 − offshore	-	833	833
Other – **Note 2**	1,886	-	1,886
March 31, 2013 ($000)	**$ 21,271**	**$ 5,145**	**$ 26,416**
	Exploration and Evaluation Assets		
	Australia	**India**	**Total**
ATP 732P – Tookoonooka **– Note 1**	$ 20,126	$ -	$ 20,126
CY-ONN-2005/1 – onshore	-	5,272	5,272
CY-OSN-2009/1 − offshore	-	-	-
Other – **Note 2**	1,423	-	1,423
March 31, 2014 ($000)	**$ 21,549**	**$ 5,272**	**$ 26,821**

Note 1: The Company entered into a farm-out agreement that requires a 2 well drilling program of which one remains to be drilled at March 31, 2014. Once the final well is drilled, the joint venture partner will earn a 50% interest in this permit and the Company will record a gain or loss on this 50% disposition.

Note 2: Other includes ATP 934P, capitalized G&A and stock-based compensation and foreign exchange effects on assets denominated in foreign currencies.

7. PETROLEUM AND NATURAL GAS PROPERTIES

		Petroleum and Natural Gas Properties		Corporate Assets		Total
$000s				**$000s**		**$000s**
Cost:						
Balance at April 1, 2012		**5,497**		**301**		**5,798**
Additions and acquisitions		7,727		126		7,853
Capitalized share based compensation		19		-		19
Change in decommissioning obligation		85		-		85
Exchange adjustments		482		-		482
Balance at March 31, 2013	**$**	**13,810**	**$**	**427**	**$**	**14,237**
Additions		7,448		(99)		7,349
Acquisitions		6,964		-		6,964
Capitalized share based compensation		93				93
Change in decommissioning obligation		38				120
Exchange adjustments		51		(10)		41
Balance at March 31, 2014		**28,404**		**318**		**28,722**

		Petroleum and Natural Gas Properties		Corporate Assets		Total
		$000s		**$ 000s**		**$000s**
Accumulated depletion, depreciation and impairment losses:						
Balance at April 1, 2012		**975**		**88**		**1,063**
Depletion and depreciation charge		1,300		75		1,375
Exchange adjustments		172		(3)		169
Balance at March 31, 2013	**$**	**2,447**	**$**	**160**	**$**	**2,607**
Depletion and depreciation charge		4,455		76		4,531
Exchange adjustments		(83)		(2)		(85)
Balance at March 31, 2014		**6,819**		**234**		**7,053**
Net carrying value						
At March 31, 2013	$	11,363	$	267	$	11,630
At March 31, 2014	**$**	**21,585**	**$**	**84**	**$**	**21,669**

The calculation of depletion for the year ended March 31, 2014 included $83.5 million and $0.5 million for estimated future development costs associated with proved and probable reserves in Australia and Canada respectively (March 31, 2013 - $31.1 million and $0.5 million).

Bengal closed its agreement to acquire an incremental 5.357% working interest in the Cuisinier oil field on December 18, 2013 for a purchase price of AUS $7.5 million / C$ 7.2 million less final closing adjustments currently estimated at $0.6 million. The Acquisition also includes a further 8.08% interest in the Wompi Block (ATP 752), resulting in working interests in those two projects of 30.357% and 38.08% respectively. The acquisition was accounted for as a business combination under IFRS 3 – "Business Combinations" and had the acquisition closed on April 1, 2013, the Company estimates that its pro forma revenue and earnings before tax for the nine month period ended December 31, 2013 would have been $17.4 million and $3.9 million respectively. Between the acquisition closing date and December 31, 2013, approximately $44,000 of production revenue and $13,000 of earnings before tax were recognized relating to the acquired properties.

$000s	
Net assets acquired	6,760
Decommissioning liabilities	(44)
Total net assets acquired	**6,716**
Consideration	**$ 6,716**

8. PROPERTY, PLANT AND EQUIPMENT

($000s)	Rig Equipment
Balance at March 31, 2012	$ 230
Additions	4,511
Capitalized share-based compensation	15
Balance at March 31, 2013	**$ 4,756**
Additions	371
Balance at March 31, 2014	**5,127**
Accumulated depletion, depreciation and impairment losses:	
Balance at March 31, 2013	**$ 73**
Impairment	1,557
Balance at March 31, 2014	**$ 1,627**
Net book value	
Balance at March 31, 2013	**$ 4,683**
Balance at March 31, 2014	**$ 3,500**

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 were 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 on permit ATP 732.

At March 31, 2014, the drilling rig had been idle for more than 12 months, which has been identified as a potential trigger for impairment. The Company estimated the recoverable amount of $3.5 million based on a fair value less costs-to-sell methodology using recent market transactions as a fair value estimate. As a result, the Company recognized a $1.6 million impairment charge during Q4 2014 related to the drilling rig.

9. INCOME TAXES

The provision for income taxes differs from the amount obtained in applying the combined Federal and Provincial income tax rates to the loss for the year. The difference relates to the following items:

Years Ended March 31 ($000s)	2014	2013
Income (loss) before taxes	95	$ (1,807)
Statutory tax rate	25%	25%
Expected income tax (expense) recovery	(24)	$ 452
Foreign exchange	83	(14)
Stock-based compensation	(121)	(124)
Effect of change in tax rate & other	(311)	(118)
Changes in unrecognized tax asset	428	(188)
Income tax recovery	55	$ 8

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

As of March 31 ($000s)		2014		2013
Non-capital losses	$	26,395	$	28,144
Net capital losses		6,033		5,998
P&NG properties		5,033		3,939
Share issue costs		720		765
Decommissioning obligations		358		320
	$	38,539	$	39,166

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

As of March 31 ($000s)		2014		2013
Property, plant & equipment		12,737	$	9,668
Foreign exchange		331		339
Non-capital losses		(13,068)		(10,007)
	$	-	$	–

At March 31, 2014, the Company had approximately $23.7 million and $46.5 million of non-capital losses in Canada and Australia respectively (2012 - $18.5 million and $43.0 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2014 to 2033. The Australian non-capital losses have no term to expiry.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2014, the Company has no deferred tax liabilities in respect of these temporary differences.

10. CONVERTIBLE AND NON-CONVERTIBLE NOTES

January 25, 2013

On January 25, 2013 the Company closed a non-brokered private placement (the "Private Placement") of $3.5 million short-term, unsecured convertible and non-convertible notes (the "Notes"). The Private Placement consists of the placement of: (i) $1,750,000 aggregate principal amount of non-convertible notes (the "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 (the "Convertible Notes") bearing an interest rate of prime plus 3% per annum and having a term of 180 days.

July 18, 2013

On July 18, 2013, $1.5 million of the Convertible Notes were converted into 2,678,572 common shares of the Company at a conversion price of $0.56 per share. On July 22, 2013 the remaining $250,000 of outstanding Convertible Notes were repaid. On April 18, 2013 the Non-convertible Note Holders agreed to extend the term of the Note from July 24, 2013 to January 24, 2014 at which time the Non-convertible Notes were extended further to January 24, 2015. As consideration for the extension the Company has agreed to increase the interest rate payable on the Notes to 10% effective July 25, 2013. The fair value of the debt approximates the carrying value, therefore no adjustment was recognized on either extension.

Convertible Note	Total	Liability component	Equity Component
	\$000s	**\$ 000s**	**\$000s**
Gross proceeds	1,745	1,720	25
Accretion on debt	30	30	-
Conversion of debt	(1,500)	(1,500)	-
Repayment of debt	(250)	(250)	-
Transfer to contributed surplus	(25)	-	(25)
Balance at March 31, 2014	**-**	**-**	**-**

Non-Convertible Note	Total
	\$000s
Balance at March 31, 2013	1,720
Accretion on debt	30
Balance at March 31, 2014	\$1,750

On July 5, 2013 the Company closed a non-brokered private placement of 8,000 units at a price of \$1,000 per unit for aggregate gross proceeds of \$8.0 million. The proceeds from the private placement were used to fund the Company's purchase of an additional 5.357% interest in its Cuisinier property, located in the Cooper-Eromanga Basin in Queensland, Australia. The acquisition had an effective date of March 15, 2013 and closed on December 18, 2013.

Each unit consists of \$1,000 principal amount of 10% unsecured non-convertible redeemable notes and either: (i) 156.25 common share purchase warrants, in the case of subscriptions by non-insiders, or (ii) 156.25 value appreciation rights ("VARs"), in the case of subscriptions by insiders. The notes bear interest at a rate of 10% per annum, payable quarterly, and have a term of 36 months. Following the first anniversary of the closing date of the private placement, the Company shall be required to make quarterly repayments of the outstanding principal of Notes in an amount equal to 6.25% of the principal amount of notes outstanding on the last day of each applicable quarter. Each whole warrant entitles the holder thereof, for a period of 36 months following the closing date, to acquire one common share in the capital of the Company at a purchase price equal to \$0.75 per share. Each whole VAR entitles the holder thereof, for a period of 36 months following the closing date, to exercise the VAR and thereby receive a cash payment equal to the difference between the market price of one common share on the exercise date and \$0.75. Certain insiders of the Company purchased 3,500 Units and received 546,875 VARs, and 4,500 Units were purchased by non-insiders who received 703,125 warrants.

The warrants are valued based on the following key assumptions: a term of 3 years, volatility of 73% and a price of \$0.75/share, which is equivalent to the preliminary VAR valuation.

Non-Convertible Note – Issued July 5, 2013	Total	Debt Component	Other long term liability	Warrants
	$000s	$000s	$000s	$000s
Gross proceeds	$ 8,000	$ 7,593	$ 178	$ 229
Total cash fees	(257)	(256)	6	(7)
	7,743	7,337	184	222
Accretion on debt/Change in fair value of VARs	33	156	(123)	-
Deferred tax impact	(55)	-	-	(55)
Balance at March 31, 2014	**$ 7,721**	**$ 7,493**	**$ 61**	**$ 167**

11. DECOMMISSIONING AND RESTORATION LIABILITY

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

Changes to decommissioning and restoration obligations were as follows:

($000s)	March 31, 2014	March 31, 2013
Decommissioning liabilities, beginning of year	**$ 320**	**$ 228**
Revision	**(82)**	**(55)**
Additions	**120**	**140**
Accretion	**8**	**7**
Exchange adjustments	**(8)**	
Decommissioning liabilities, end of year	**$ 358**	**$ 320**

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at March 31, 2014 is approximately $567,000 (March 31, 2013 – $421,000) which will be incurred between 2015 and 2038. An inflation factor ranging between 1.0% and 2.5% and a risk free discount rate ranging between 1.5% and 4.1% have been applied to the decommissioning liability at March 31, 2014.

12. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares with no par value.

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

(b) Issued:

The following provides a continuity of share capital:

($000s)	Number of Shares	Amount
Balance at March 31, 2012 and 2013	52,110,177	**$ 86,246**
Shares issued for cash	9,500,666	**5,700**
Issued on conversion of convertible debentures	2,678,572	**1,500**
Issued on exercise of stock options for cash	351,667	**127**
Issued on cashless exercise of stock options	26,000	**-**
Share issue costs	-	**(422)**
At March 31, 2014	**64,667,082**	**93,151**

On April 16, 2013 the Company issues a total of 9,5000,666 Common Shares at a price of $0.60 per Common Share for aggregate gross proceeds of $5.7 million. The Company paid the Agents a cash commission of $0.3 million. A total of 2,400,300 shares of the Offering were purchase by insiders of the Company.

On July 18, 2013 1$1.5 million of convertible debentures were converted into 2,678,572 Common Shares at a price of $0.56 per common share.

(c) Share-based compensation – stock options:

The Company has a share option plan for directors, officers, employees and consultants of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of three to five years and vest one-third immediately and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. Effective with the option grant on December 21, 2012, vesting occurs one third after the first year and one third on each of the two subsequent anniversaries.

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

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2012	**3,611,665**	**$ 1.14**
Granted	1,150,000	0.58
Expired	(416,667)	1.30
Forfeited	(148,333)	1.11
Outstanding at March 31, 2013	**4,196,665**	**$ 0.98**
Granted	1,195,000	0.62
Forfeited	(270,001)	0.71
Expired	(846,664)	1.23
Exercised	(401,667)	0.36
Outstanding at March 31, 2014	**3,873,333**	**$ 0.89**
Exercisable at March 31, 2014	**2,520,005**	**1.04**

	Options Outstanding			Options Exercisable	
Option Price (1)	**Number Outstanding**	**Exercise Price (2)**	**Remaining Life (3)**	**Number Exercisable**	**Exercise Price (2)**
$0.47 - $0.65	2,063,333	$0.60	4.07	710,005	$0.60
$0.66 - $1.25	1,230,000	$1.17	2.92	1,230,000	$1.17
$1.26 - $1.32	580,000	$1.32	2.25	580,000	$1.32
Total	**3,873,333**	**0.91**	**3.43**	**2,520,005**	**1.04**

(1) Range of option exercise prices

(2) Weighted average exercise price of options

(3) Weighted average remaining contractual life of options in years

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

For the Year Ended	March 31, 2014	March 31, 2013
Assumptions:		
Risk free interest rate (%)	**2.0%**	2.0%
Expected life (years)	**5 yr**	5 yr
Expected volatility (%)(1)	**73%**	86%
Estimated forfeiture rate (%)	**7.1%**	6.5%
Weighted average fair value of options granted	**$0.37**	$0.40
Weighted average share price on date of grant	**$0.62**	$0.58

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

The fair value of stock options granted during the year ended March 31, 2014 was $417,000 (2013 - $454,000).

(d) Per share amounts:

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

For the Year Ended ($000s)	March 31, 2014	March 31, 2013
Income (loss) for the year	**150**	(1,799)
Weighted average number of common shares (basic)	63,134	52,110
Weighted average number of common shares (diluted)	63,209	52,110
Basic and diluted income (loss) per share	**0.00**	(0.03)

At March 31, 2014, there were 2,683,000 (March 31, 2013 – 4,196,665) options considered anti-dilutive. In addition, there were 703,125 warrants and 546,875 value appreciation rights considered anti-dilutive.

13. COMPENSATION OF KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

Year ended March 31 ($000s)	2014	2013
Salaries & employee benefits	**$ 930**	$ 822
Stock-based compensation(1)	**208**	496
General & administrative expenses	**$ 1,138**	$ 1,318

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

Salaries and benefits for the year ended March 31, 2014 include a non-recurring retirement payment to former employees of $0.2 million (2013 - $nil).

14. FINANCE EXPENSES

Year ended March 31 ($000s)	2014	2013
Accretion on decommissioning obligations	**$ 8**	$ 7
Performance Security Guarantee fee (1)	**72**	43
Interest on Notes payable	**756**	38
Accretion on Notes payable and change in fair value of VARs	**93**	45
Finance expenses	**$ 929**	$ 133

(1) Fees paid to Export Development Canada and ICICI Bank for security guarantees for onshore and offshore India work programs.

15. FINANCIAL RISK MANAGEMENT

The Company has exposure to credit, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives and policies and processes for measuring and managing risk.

The Board of Directors has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. Bengal's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

(a) Fair value of financial instruments:

Financial instruments comprise cash, cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities and notes payable. The fair values of these financial instruments approximate their carrying amounts due to their short-term maturities, with the exception of notes payable. The fair value of notes payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2014 and March 31, 2013 the fair value of these balances approximated their carrying value due to their short term to maturity

(b) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at March 31, 2014, Bengal's receivables consisted of $3.5 million (March 31, 2013 - $3.4 million) from joint venture partners and $0.3 million (March 31, 2013 - $0.2 million) of other trade receivables of which $3.4 million has been subsequently collected.

Production from the Canadian operations is marketed by the operator. Bengal established a payment schedule with the operator of the property and considers the entire amount to be receivable.

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 March 31, 2014, the Company had $0.1 million that were considered past due (past due is considered greater than 90 days outstanding). Bengal believes these receivables will be collected.

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 March 31, 2014 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended March 31, 2014.

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.

(c) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due. Bengal's financial liabilities consist of accounts payable, accrued liabilities and Notes payable and amounted to $13.4 million at March 31, 2014 (March 31, 2013 - $8.1 million). Bengal had $6.0 million in cash (March 31, 2013 - $2.6 million), $0.1 million in restricted cash (March 31, 2013 - $0.1 million) and a working capital surplus of $3.1 million at March 31, 2014 (March 31, 2013 – deficit of $1.6 million). All accounts payable and accrued liabilities are due within one year.

The table below indicates the payment schedule for o/s notes payable:

Note issued/extended	July 5, 2013	January 24, 2014
Fiscal year 2015	1,408	1,750
Fiscal year 2016	1,500	-
Fiscal year 2017	5,092	-
	$ 8,000	**$ 1,750**

(d) Market risk:

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to these risks.

Foreign Currency Risk

Foreign currency exchange rate risk is the risk that the fair value 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:

As at March 31, 2014 ($000s)	CAD	AUD	U.S.D
Cash and short-term deposits	$ 299	$ 1,235	$ 4,443
Restricted cash	140	-	-
Accounts receivable	105	3,700	-
Accounts payable and accrued liabilities	(625)	(3,046)	298
Notes payable and other long term liability	(9,304)	-	-
	$ (9,385)	**$ 1,889**	**$ 4,741**

Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the Daily Brent reference price, which trades at a premium to WTI. There were no financial instruments in place to manage commodity prices during the year ended March 31, 2014.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is not exposed to interest rate risk on its cash and cash equivalents at March 31, 2014 as the funds are not invested in an interest bearing instrument. The Company is also exposed to interest rate risk on its Notes Payable. A 1% increase in the Prime rate would increase interest expense on the Notes by $97,500. The Company had no interest rate derivatives at March 31, 2014.

16. CAPITAL MANAGEMENT

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, which will allow it to execute on its capital investment program, provide creditor and market confidence and to sustain future development of the business.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions, including: changes in economic conditions, the risk profile of its drilling inventory, the efficiencies of past investments, the efficiencies of forecasted investments and the timing of such investments, the forecasted cash balances, the forecasted commodity prices and resulting cash flow.

In order to maintain or adjust the capital structure, the Company may from time to time issue shares (if available on reasonable terms), issue debt instruments, sell assets, farm out properties and adjust its capital spending to manage current and projected cash levels. There can be no assurance that equity financing will be available or sufficient to meet capital commitments, or for other corporate purposes, or if equity financing is available, that it will be on terms acceptable to the Company. The Company presently does not have a credit facility in place but based on project viability may arrange separate project financing. There has been no change in capital management and no externally imposed capital restrictions during the year.

17. CHANGES IN NON-CASH WORKING CAPITAL

Year ended March 31 ($000s)		2014		2013
Accounts receivable	**$**	**(271)**	$	(3,034)
Prepaid expenses and deposits		**(380)**		17
Accounts payable and accrued liabilities		**(449)**		2,139
Impact of foreign exchange		**(305)**		221
Total	**$**	**(1,405)**	$	(657)
Relating to:				
Operating	**$**	**(592)**	$	(1,802)
Financing		**(808)**		38
Investing		**(5)**		1,107
Total	**$**	**(1,405)**	$	(657)

The following represents the cash interest received in each period.

Year ended March 31 ($000s)		2014		2013
Cash interest received	**$**	**74**	$	274

18. COMMITMENTS AND CONTINGENCIES

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.

Country and Permit	Work Program	Obligation Period Ending	Estimated Expenditure (net) (millions CAD$)(1)
Cuisinier (ATP 752 – Bart permit)	Two well exploration program	September 30, 2014	$1.6
Onshore India – CY-ONN-2005/1	Three wells	February 25, 2015(2)	$3.8
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014(3)	$5.5

(1) Translated at March 31, 2014 at an exchange rate of US $1.0000 = CAD $1.10, and AUS $1.00 = CAD $1.025
(2) If the Company did not participate in the drilling of three wells, costs of $5.2million would be impaired and the Company's interest in the permit would decline.
(3) The Company expects to relinquish this permit on or before its expiry date, resulting in an impairment of 100% of the asset's carrying value and a provision for expected penalties.

At March 31, 2014 the Company had the following lease commitment for office space in Canada.

($000s)					
April 2014 to March 2017	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 775	258	517	-	-

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

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	$ 11.9

19. SUPPLEMENTAL DISCLOSURE

Bengal's consolidated statement of income (loss) and comprehensive income (loss) is prepared primarily by nature of expense. All salaries for the Company are included in general and administrative expenses and for the year ended March 31, 2014 amount to $1.4 million (2013 - $1.0 million).

20. RELATED PARTY TRANSACTIONS

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. Members of the Board of Directors of the Company subscribed for approximately 85% of the principal amount of the notes issued pursuant to the Private Placement.

21. SUBSEQUENT EVENT

On May 27, 2014 Bengal announced it had entered into an indicative term sheet for a US $20.0 million secured credit facility (the "Facility") with a leading Australian commercial bank (the "Lender"). The Facility contemplates a borrowing base of up to US $20 million, over a three year term at attractive fixed income market rates tied to USD LIBOR to fund its ongoing Australian development. The Facility remains subject to the completion of due diligence by the Lender and the entering into of a final Offer to Finance with Bengal and will remain open for a fixed period to allow Bengal to review other competitive lending proposals that may be received.

22. SEGMENTED INFORMATION

As at March 31, 2014, the Company has three reportable operating segments being the Australian, Canadian and India oil and gas operations.

Revenue reported below represents revenue generated from external customers. There were not 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 year ended March 31, 2014 ($000)	Australia	Canada	India	Total
Revenue	19,480	342	-	19,822
Interest revenue	73	1	-	74
Interest expense	-	777	-	777
Depletion and depreciation	4,435	96	-	4,531
Net (earnings) loss	6,802	(4,976)	(1,676)	150
Exploration and evaluation expenditures	767	-	1,196	1,963
Petroleum and natural gas property expenditures	14,313	-	-	14,313
Property, plant & equipment expenditures	-	371	-	371
Impairment losses (recovery)	-	(1,928)	(1,173)	3,101
March 31, 2014 ($000)				
Petroleum and natural gas properties				
Cost	24,105	4,617	-	28,722
Impairment loss	-	-	-	-
Accumulated depletion, depreciation and accretion	(3,034)	(4,019)	-	(7,053)
Net book value	21,072	598	-	21,669
Exploration and evaluation assets	30,619	-	6,993	37,612
Accumulated impairment losses	(9,621)	-	(1,170)	(10,791)
Net book value	20,998	-	5,823	26,821
Property, plant & equipment	-	5,127	-	5,127
Accumulated depletion, depreciation and accretion	-	(70)	-	(70)
Impairment	-	(1,557)	-	(1,557)
Net book value	-	3,500	-	3,500

For the year ended March 31, 2013 ($000)	Australia	Canada	India	Total
Revenue	$ 5,669	$ 216	$ -	$ 5,885
Interest revenue	82	87	(2)	167
Interest expense	-	38	-	38
Depletion and depreciation	1,255	193	-	1,448
Net loss	1,266	(2,251)	(814)	(1,799)
Exploration and evaluation expenditures	13,167	-	2,850	16,017
Petroleum and natural gas property expenditures	$ 7,876	$ (23)	$ -	$ 7,853
Property, plant & equipment expenditures	$ -	$ 4,511	$ -	$ 4,511
Impairment losses (recovery)	80	-	-	80
March 31, 2013 ($000)				
Petroleum and natural gas properties				
Cost	$ 13,065	$ 1,172	$ -	$ 14,237
Impairment loss	-	(311)	-	(311)
Accumulated depletion, depreciation and accretion	(1,828)	(468)	-	(2,296)
Net book value	$ 11,237	$ 393	$ -	$ 11,630
Exploration and evaluation assets	$ 26,393	-	$ 5,145	31,538
Accumulated impairment losses	(5,122)	-	-	(5,122)
Net book value	$ 21,271	$ -	$ 5,145	$ 26,416
Property, plant & equipment	$ –	$ 4,756	$ –	$ 4,756
Accumulated depletion, depreciation and accretion	–	(73)	–	(73)
Net book value	$ –	$ 4,683	$ –	$ 4,683

CORPORATE INFORMATION

AUDITORS

KPMG LLP • Calgary, Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP • Calgary, Canada
Johnson Winter Slattery • Brisbane, Australia

BANKERS

Royal Bank of Canada • Calgary, Canada
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

5 Quarters Investor Relations, Inc. • Calgary, Canada

DIRECTORS

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

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All Directors are members of the Committee

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Robert D. Steele
W.B. (Bill) Wheeler

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

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

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

STOCK EXCHANGE LISTING – TSX:BNG