International Exploration and Production

Bengal
ENERGY LTD.

Annual Report | 2010

TABLE OF CONTENTS

THE BENGAL EDGE

A veteran team
with **international experience**

World-class **resource plays**
in stable countries

A balance of **exploration**
and exploitation

LETTER TO SHAREHOLDERS

Bengal moved aggressively in fiscal 2010 to establish a platform for significant international growth. Within the past two years we have increased our undeveloped land position by 250% to 2.3 million net acres and have moved from a primarily non-operated land base to the point where we operate 87% of our net acreage. To put the depth of our oil and natural gas prospects in perspective, the size of our undeveloped land base in India and Australia now surpasses the 2009 acreage of every publicly traded junior and intermediate oil and natural gas company operating in Western Canada.

Bengal's land position is highly prospective. After using rigorous technical work to identify suitable prospects, we've been granted four large exploration blocks at recent international bid rounds in proven, producing basins in onshore and offshore India and Australia.

Most recently, the Government of the State of Tamil Nadu granted a formal Petroleum Exploration License in March 2010 on 234,000 acres in India's Cauvery Basin to a consortium including Bengal. Bengal has a 30% interest in the onshore block CY-ONN-2005/1 while the operator, GAIL (India) Limited, holds a 40% interest and the Gujarat State Petroleum Corporation holds the remaining 30% interest. With the granting of the formal license, exploration work has now begun, consisting of 2D seismic reprocessing, an aeromagnetic survey and a large 3D seismic program. This work will set up a three-well drilling program targeting oil in multiple proven play types within the Cauvery Basin.

We also have significant potential on 340,000 acres at CY-OSN-2009/1 in the shallow offshore area of the southern Cauvery Basin. We were provisionally awarded this acreage (100% working interest) in October 2009 as part of India's latest New Exploration Licensing Policy bid round (NELP VIII). We have received notice from the Indian Government that the Production Sharing Contract will be signed by July, 2010. Our technical review of existing 2D seismic on the block has identified a large structure approximately 18,000 acres in size. We will be targeting a 3D seismic program to further evaluate the structure and develop a follow-up drilling program. The Cauvery Basin is an active region in the southern part of the east coast of India with 28 producing oil and gas fields. Oil companies within 50 km of our block have committed to spend in excess of $200 million on exploration over the next four years.

In March 2009, Bengal was awarded a 100% working interest in exploration permit AC/P 47, an 861,000-acre block offshore Australia in the Timor Sea. An appraisal by DeGolyer and MacNaughton (D&M), a worldwide petroleum consulting company, resulted in a "best" estimate of the permit's gross prospective resources of 590.4 million barrels of recoverable oil as at March 31, 2009. The assessment had a low estimate of 206.5 million barrels and a high estimate of 1,456.7 million barrels. Gross prospective resources are those quantities of petroleum that are estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. There is no certainty that any portion of the prospective resources will be discovered and, if discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Further details of this assessment can be found on our website or in our SEDAR filings. Bengal has purchased additional 2D seismic data, commenced reprocessing of older 2D data, and will be acquiring a large 3D over the main prospect area.

We also expanded our operations in Australia by signing an agreement in December 2009 to acquire a 100% working interest in Authority to Prospect 732P (ATP 732P), a 654,000 acre exploration block in Australia's Cooper Basin. The new block, located near producing oil and gas fields, has a 12-year term with a commitment to drill at least one well within the first four years. This was the fourth major exploration play acquired and announced by Bengal since March 2009.

Bengal's acreage is noteworthy in a number of ways. Our recent acquisitions and earned lands offer us multiple plays with managed risk in stable jurisdictions. Managing our risk means carefully selecting our prospects and partners, high operatorship and restricting our operations to countries with economic stability, all to minimize our risk and maximize our potential reward. In addition, our acreage offers both immediate production and high impact prospectivity.

The expansion of our land base in India and Australia is consistent with our strategy of seeking prospects and partners – including five National Oil Companies – that allow for low capital commitments for exploration in the initial years with high-impact drilling opportunities in underexploited areas.

Producing Results

Although we have been focusing our attention on forming partnerships and finding prospects, we also have a production base from which to grow. In fiscal 2010, we generated revenue of $830,000 from 134 barrels of oil equivalent per day (boe/d) of production in Canada and Australia. In September 2009 we sold our non-core producing assets in the Kaybob region of Alberta (29 boe/d) for $2.1 million.

We expect our production base to grow in fiscal 2011. On June 8, 2010, we announced that production had commenced from our Cuisinier-1 oil discovery in Australia's onshore Cooper Basin. The well, drilled under the ATP 752P staged farm-in agreement, is producing at a rate of 340 barrels of 52 degree API oil per day. Our interest in the well and the surrounding 631,000-acre Barta Block is 14.26%. We will increase our interest to 25% at ATP 752P following completion of the second phase of the farm-in agreement. The agreement calls for Bengal to contribute 55% of the cost to drill the next earning well. In addition, Bengal is fully carried on up to two additional exploration wells at ATP 752P.

In fiscal 2011, we're committed to continuing to pursue land positions with operational control, minimal upfront capital requirements, high working interests and strong prospectivity. We're also open to reviewing mergers, acquisitions and partnerships that will enhance our portfolio of projects.

While the search continues for prospects, we're well positioned for organic growth. As we move from a period of land acquisitions into active exploration and exploitation, we believe our deep inventory of opportunities in India and Australia set the stage for long-term growth. With the prospects in place, the key now is to select the financial partners to facilitate our expansion and share in our success.

Sincerely,

Bradley Johnson

Bradley Johnson
Chairman and CEO

Chayan Chakrabarty

Chayan Chakrabarty
President

MANAGEMENT'S DISCUSSION AND ANALYSIS

June 7, 2010

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2010 and 2009. Additional information relating to the Company, including detailed reserve disclosures, is included in our Annual Information Form, which will be filed on SEDAR at www.sedar.com. The reader should be aware that historical results are not necessarily indicative of future performance.

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

Basis of Presentation - The financial statements and data presented herein were prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the functional currency is the Canadian dollar. 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. The following definitions are used in this MDA: boe/d means barrels of oil equivalent per day; bbl/d means barrels per day and mcf/d means thousand cubic feet per day.

This MD&A and accompanying financial statements and notes are the three-month and 12-month periods ended March 31, 2010. The terms "current quarter" and "the quarter" are used throughout the MD&A and in all cases refer to the period from January 1, 2010 through March 31, 2010. The terms "prior year's quarter" and "2009 quarter" are used throughout the MD&A for comparative purposes and refer to the period from January 1, 2009 through March 31, 2009.

The fiscal year for the Company is the 12-month period ended March 31, 2010. The terms "fiscal 2010," "current year" and "the year" are used throughout the MD&A and in all cases refer to the period from April 1, 2009 through March 31, 2010. The terms "previous year," "prior year" and "fiscal 2009" are used throughout the MD&A for comparative purposes and refer to the period from April 1, 2008 through March 31, 2009.

Non-GAAP 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 are not defined by GAAP in Canada and are referred to as non-GAAP measures. 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 flow from operations or other measures of financial performance calculated in accordance with Canadian GAAP. Funds from operations is 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 boes are calculated by multiplying the daily production by the number of days in the period.

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

	Three Months Ended			Twelve Months Ended	
$000s	**03/31/10**	03/31/09	12/31/09	**03/31/10**	03/31/09
Cash flow from (used in) operations	**(493)**	(85)	(264)	**(1,650)**	1,773
Abandonment expenditures	**-**	-	-	**21**	12
Changes in non-cash working capital	**(133)**	(7)	(83)	**63**	(680)
Funds from (used in) operations	**(626)**	(92)	(347)	**(1,566)**	1,105

Forward-looking Statements - *Certain statements contained within the Management's Discussion and Analysis, and in certain documents incorporated by reference into this document, constitute forward-looking statements. These statements relate to future events or Bengal's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "targeting," "intend," "could," "might," "should," "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this MD&A should not be unduly relied upon.*

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

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and TAPIS daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements ;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1and successful execution of a Production Sharing Contract on this Block;*
- *Continuation of exploration, development and drilling activities on Permits AC/P 47 and AC/P 24 offshore Australia;*
- *Closing of the acquisition of ATP 732P and obtaining Native Title Agreement on ATP 934P in Australia;*
- *Estimates of start up date and production levels for the Cuisinier well in Australia;*
- *Additional exploration and exploitation opportunities identified from the Cuisinier seismic will lead to prospects and;*
- *Future amount and timing of activity to be carried out by the Santos Joint Venture.*

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;*
- *There is a 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.

HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	03/31/09
Revenue					
Natural gas	**$ 206**	$ 357	$ 186	**$ 830**	$ 2,110
Natural gas liquids	**22**	62	19	**163**	473
Oil	**52**	248	208	**779**	2,343
Total	**280**	667	413	**1,772**	4,926
Royalties	**39**	143	53	**231**	882
% of revenue	**13.9**	21.4	12.7	**13.0**	17.9
Operating & transportation	**116**	283	164	**756**	1,145
Netback[1]	**125**	241	196	**785**	2,899
Cash flow from (used in) operations:	**(493)**	(85)	(264)	**(1,650)**	1,773
Per share ($) (basic & diluted)	**(0.03)**	(0.00)	(0.01)	**(0.09)**	0.10
Funds from (used in) operations[2]:	**(626)**	(92)	(347)	**(1,566)**	1,105
Per share ($) (basic & diluted)	**(0.03)**	(0.01)	(0.02)	**(0.08)**	0.06
Net (loss):	**(1,396)**	(839)	(885)	**(4,991)**	(8,198)
Per share ($) (basic & diluted)	**(0.08)**	(0.05)	(0.05)	**(0.27)**	(0.45)
Capital expenditures	**$ 553**	$ 254	$ 1,120	**$ 1,401**	$ 6,724
Property disposition proceeds	**$ –**	$ –	$ –	**$ 2,111**	$ –
Volumes					
Natural gas (mcf/d)	**377**	712	422	**568**	724
Natural gas liquids (boe/d)	**5**	19	6	**11**	19
Oil (bbl/d)	**7**	44	24	**28**	58
Total (boe/d @ 6:1)	**75**	182	100	**134**	198
Netback[1] ($/boe)					
Revenue	**$ 41.65**	$ 40.81	$ 44.89	**$ 36.44**	**$** 68.20
Royalties	**5.79**	8.72	5.69	**4.74**	12.21
Operating & transportation	**17.19**	17.23	17.81	**15.53**	15.84
Total	**$ 18.67**	$ 14.86	$ 21.39	**$ 16.17**	$ 40.15

(1) Netback is a non-GAAP 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-GAAP measure. The comparable GAAP measure is cash flow from operations. A reconciliation of the two measures can be found in the table on page 5.

RESULTS OF OPERATIONS

Production

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

Production	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Natural gas (mcf/d)	**377**	712	422	**568**	724
NGLs (boe/d)	**5**	19	6	**11**	19
Oil (bbls/d)	**7**	44	24	**28**	58
Total (boe/d)	**75**	182	100	**134**	198

For the year ended March 31, 2010, total oil, natural gas and natural gas liquids (NGLs) production averaged 134 boe/d, a decrease of 32% from the 198 boe/d produced in the prior fiscal year. The decrease in production is mainly due to the sale of four Kaybob gas wells in Canada on September 24, 2009 and lower oil production from the Toparoa well in Australia which was shut-in due to extensive flooding in the Cooper Basin of Australia in early February, 2010. The Toparoa well remains shut-in but industry activity is gradually starting up again as the flood waters dry up and Toparoa is expected to re-commence production in June 2010. In the three month period ended March 31, 2010 total production averaged 75 boe/d, a decline of 59% from the prior year period of 182 boe/d due to the sale of four Kaybob gas wells and the flooding related shut-in of the Toparoa well. The decrease from Q3-2010 production of 100 boe/d to 74 boe/d in Q4-2010 is due to reduced production from the Toparoa well.

Oil production averaged 28 bbl/d in fiscal 2010, an decrease of 52% from 58 bbl/d in the prior fiscal year mainly due to natural decline as well as the shut-in of the well due to flooding.

Natural gas production averaged 568 mcf/d during the current fiscal year, a decrease of 21% over the prior fiscal year average of 724 mcf/d. For the three months ending March 31, 2010 gas production averaged 377 mcf/d, a decrease of 47% from the prior year's period of 712 mcf/d. Gas production from the Kaybob wells averaged 277 mcf/d in the first six months of fiscal 2010 prior to their sale.

Pricing

Oak, British Columbia gas sales are marketed by the operator and the price received is based on the reference price at British Columbia's Station 2 plus $0.03 per mcf.

NGLs include condensate, pentane, butane and propane. While prices for condensate and pentane have a relatively strong correlation to oil prices, prices for butane and propane trade at varying discounts due to the market conditions of local supply and demand. Bengal had two NGL marketing contracts which expired March 31, 2010. Both contracts were assigned to the purchaser on close of the sale of the Kaybob property in September 2009.

Bengal's realized price for its Australian oil production is based on the Tapis Crude benchmark price plus a small quality premium. Tapis is the main regional reference price for light sweet crude oils in South East Asia and is used as the reference price for Australian oil producers. Tapis has been trading at an average premium to West Texas Intermediate (WTI) of U.S. $2.71 per bbl over the past year.

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

Prices and Marketing	**Three Months Ended**			**Twelve Months Ended**	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Average Benchmark Prices					
AECO 30 day firm ($/mcf)	**$ 5.35**	$ 5.62	$ 4.23	**$ 4.06**	$ 7.79
TAPIS oil ($US/bbl)	**81.27**	49.03	77.15	**73.41**	91.28
Cdn/Aus exchange rate	**0.94**	0.83	0.96	**0.93**	0.88
WTI oil ($US/bbl)	**$ 78.79**	$ 43.21	$ 76.16	**$ 70.70**	$ 86.52
Bengal's Realized Price ($ CAD)					
Natural gas ($/mcf)	**$ 6.08**	$ 5.58	$ 4.80	**$ 4.00**	$ 7.98
Oil ($/bbl)	**81.62**	61.91	96.58	**77.21**	110.01
NGLs ($/bbl)	**51.69**	37.17	31.74	**41.17**	68.92
Total ($/boe)	**$ 41.65**	$ 40.81	$ 44.89	**$ 36.44**	$ 68.20

Bengal's total realized price on a boe basis declined 47% or $31.76/boe year over year as a result of declines in the market prices for oil and gas.

Petroleum and Natural Gas Sales

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

Petroleum and Natural Gas Sales ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Natural gas	**$ 206**	$ 357	$ 186	**$ 830**	$ 2,110
NGLs	**22**	62	19	**163**	473
Oil	**52**	248	208	**779**	2,343
Total	**$ 280**	$ 667	$ 413	**$ 1,772**	$ 4,926

Revenue for the 2010 fiscal year was 64% lower than the prior fiscal year due to decreased overall production as well as lower average commodity prices realized over the period.

Revenue in the current quarter decreased 32% from the third quarter due to lower oil production and prices and 58% from the prior year's quarter due to lower oil and gas production.

Royalties

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

In Alberta, royalties on natural gas and NGLs are charged by the government based on an established monthly reference price. Bengal also paid a 7.5% gross overriding royalty (GORR) on two of the Kaybob gas wells which were sold on September 24, 2009.

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

In Australia, oil royalties are based on a Government established rate of 11%. 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 11%.

For the 2010 fiscal year royalties were 74%, or $651,000 lower than the previous fiscal year due to decreased production and lower average commodity prices during the year. Royalties per boe decreased as gas royalties are based on a sliding scale and as gas prices decline below a certain point, royalty rates decline proportionately more than prices. Royalties paid in the current quarter decreased 26% from the prior quarter due to lower oil production. Royalties were 74% lower than the prior year's quarter due to lower production.

Royalties by Type ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Canada Crown	**$ 17**	$ 73	$ 23	**$ 98**	$ 485
Canada gross overriding	**17**	8	12	**60**	148
Australian Government	**5**	62	18	**73**	249
Total	**$ 39**	$ 143	$ 53	**$ 231**	$ 882
$/boe	**5.79**	8.72	5.69	**4.74**	12.21
% of revenue	**13.9**	21.4	12.7	**13.0**	17.9

Royalties by Commodity	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Natural gas					
$000s	**$ 29**	$ 62	$ 30	**$ 122**	$ 493
$/mcf	**0.85**	0.94	0.77	**0.58**	1.86
% of revenue	**14.1**	16.9	16.1	**14.6**	23.3
Oil					
$000s	**$ 5**	$ 62	$ 18	**$ 73**	$ 249
$/bbl	**7.58**	15.53	8.23	**7.23**	11.72
% of revenue	**9.3**	25.1	8.5	**9.4**	10.6
NGLs					
$000s	**$ 5**	$ 19	$ 5	**$ 36**	$ 140
$/bbl	**11.99**	11.96	8.07	**9.17**	20.42
% of revenue	**23.2**	32.2	25.4	**22.3**	29.6

Operating & Transportation Expenses

Operating and transportation expenses in the 2010 fiscal year were 34% lower than the prior fiscal year due to lower oil production in Australia and sale of four Kaybob Alberta gas wells in September, 2009. Operating and transportation costs decreased 29% in the current quarter compared to the prior quarter due to the Toparoa well in Australia being shut in for two months of the current quarter and the prior quarter included a 13th month operating cost adjustment in Canada. Operating and transportation costs decreased 59% in the current quarter compared to the prior year quarter for the same reasons discussed in the fiscal year comments above. Australian costs per boe increased in the current quarter as a certain amount of costs are fixed and with low production, costs per bbl increase.

Transportation costs in Australia are incurred to transport Bengal's oil production from the wellhead to the Limestone Creek processing facility. From there the oil is pipelined to the Moomba facility which accepts production from 115 gas fields and 39 oil fields through approximately 5,600 kilometres of pipelines. The oil is then sent through a pipeline to Port Bonython, South Australia.

Operating Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Australia					
Operating	**$ 9**	$ 24	$ 14	**$ 61**	$ 82
Transportation	**12**	51	33	**146**	276
	21	75	47	**207**	358
Canada – Operating costs	**95**	208	117	**549**	787
Total	**$ 116**	$ 283	$ 164	**$ 756**	$ 1,145
Australia					
Operating - $/boe	**14.35**	6.00	6.65	**6.00**	3.86
Transportation - $/boe	**17.66**	12.80	14.99	**14.47**	12.96
Canada - $/boe	**15.65**	16.72	16.64	**14.24**	15.43
Total ($boe)	**$ 17.19**	$ 17.23	$ 17.81	**$ 15.53**	$ 15.84

General and Administration (G&A) Expenses

General and Administrative Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
G&A	**$ 841**	$ 506	$ 540	**$ 2,431**	$ 2,247
G&A ($/boe)	**$ 125.40**	$ 30.94	$ 58.62	**$ 49.99**	$ 31.12

In fiscal 2010 G&A expenses remained basically unchanged over the prior fiscal year while G&A/boe increased by 61% over the same period due to lower production volumes in the current year while G&A remained relatively fixed.

G&A expenses increased 56% in the current quarter compared to the prior quarter and 66% compared to the prior year quarter. The increase is due to additional geological software subscriptions, investor presentations and roadshows and related promotional material, travel and consulting costs during the current quarter.

Stock-Based Compensation

Stock Based Compensation ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	03/31/09	12/31/09	03/31/10	03/31/09
Stock-based compensation	**$ 148**	$ 56	$ 146	**$ 294**	$ 236

The Company applies the fair value method for valuing stock option grants. Under this method, compensation costs attributable to all share options granted are measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus.

In February 2010, 40,000 stock options were granted to employees and directors. The options expire three years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.32 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options is $38,000 using the Black-Scholes option pricing model.

In December 2009, 612,000 stock options were granted to employees and directors. The options expire three years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries, and have an exercise price of $1.26 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options is $554,000 using the Black-Scholes option pricing model.

Fiscal 2010 stock-based compensation expense was $294,000 compared to $236,000 in the prior comparable period. The increased expense is due to an increase in the expected volatility used to calculate the fair value of the options granted in the current year. In the current year 405,000 options expired and 10,000 were forfeited which had not vested. The forfeited options reduced stock-based compensation by $9,000. At March 31, 2010 there was $244,000 of stock-based compensation remaining to be amortized over the next 2 years.

Bengal recognized stock-based compensation expense of $148,000 for the current quarter compared to $57,000 in the comparable prior year's period. The increase is again due to the increase in expected volatility used to calculate the options fair value.

Bengal recorded stock-based compensation related to outstanding warrants of $261,000 (2009 - $198,000) for the year ended March 31, 2010 and $54,000 for the three months ended March 31, 2010 (Q4-2009 - $43,000). At March 31, 2010 there is $215,000 of fair value related to the warrants to be amortized over the next year.

Depletion, Depreciation and Accretion (DD&A)

DD&A Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
DD&A – Australia	**$ 44**	$ 227	$ 176	**$ 534**	$ 2,776
DD&A – Canada	**24**	333	194	**907**	1,127
Sub-total	**68**	560	370	**1,441**	3,903
Impairment charge	**451**	–	–	**451**	3,133
Total	**$ 519**	$ 560	$ 370	**$ 1,892**	$ 7,036
$/boe – Australia	**70.79**	57.04	81.18	**52.95**	130.38
$/boe – Canada	**3.91**	26.91	27.66	**23.53**	22.12
$/boe – Subtotal	**10.20**	34.27	40.21	**29.65**	54.04
$/boe – Impairment charge	**67.27**	–	–	**9.27**	43.39
$/boe – Total	**$ 77.47**	$ 34.27	$ 40.21	**$ 38.92**	$ 97.43

Depletion, depreciation and accretion (DD&A), before impairment charges, decreased for the three and 12 months ended March 31, 2010 over the comparable prior year's periods due to lower production volumes and lower DD&A rate per boe. DD&A per boe decreased in the current quarter and current year due to positive reserve revisions at the Company's Oak B.C gas property and the Toparoa oil reserves in Australia.

At March 31, 2010 the Company recorded an unproved property impairment charge of $0.5 million pertaining to its South Larne permit in Northern Ireland. The exploration license for the permit has expired and the Company does not expect any future activity on the permit. In the prior year, a ceiling test calculation resulted in an impairment charge, related to the Australian cost centre, being included in DD&A expense.

Bengal has excluded $3.0 million from the depletion base related to Australian unproved properties at March 31, 2010 compared to $2.3 million in the prior year and has excluded $0.5 million for the India new cost centre (prior year $0.8 million for India and Ireland).

Funds from (used in) Operations and Net Loss

For the 12 months ended March 31, 2010 funds used in operations increased to ($1,566,000) or ($0.08) per basic and diluted share compared to funds from operations of $1,105,000 or $0.06 per basic and diluted share in the prior period. The decline is due to lower production volumes and commodity prices. The changes in non-cash working capital and abandonment expenditures are removed from the GAAP measure cash flow from (used in) operations to arrive at the non-GAAP measure funds from (used in) operations.

The loss for the 12 months ended March 31, 2010 was $4,991,000 or $0.27 per basic and diluted share compared to a loss of $8,198,000 or $0.45 per basic and diluted share in the prior fiscal year. The decreased loss is due to ceiling test and goodwill impairment charges of $1.8 million and $3.1 million respectively in the prior fiscal year compared to an undeveloped property impairment charge of $0.5 million in the current year offset by reduced operating netbacks.

CAPITAL EXPENDITURES

Geological and geophysical expenses totaled $1,377,000 for the year ended March 31, 2010 and $443,000 in the current quarter and relate to seismic acquisition, interpretation and analysis on all of the Company's lands including prospect identification and play development. Also included in geological and geophysical costs are costs related to acquiring Block CY-OSN-2009/1 under the NELP VIII bid round in India. The credit in drilling costs for fiscal 2010 is due the final cost of a well drilled in the prior year being less than originally estimated. Completion costs were incurred to complete and install artificial lift on the Company's Cuisinier well in the Cooper Basin of Australia.

On September 24, 2009 the Company disposed of its interest in the Kaybob property for net proceeds of $2,111,000. The disposition resulted in a $3,117,000 reduction to petroleum and natural gas assets, removal of $63,000 of asset retirement obligations and a loss of $943,000.

Capital Expenditures ($000s)	Three months ended			Twelve Months Ended	
	03/31/10	**03/31/09**	**12/31/09**	**03/31/10**	**03/31/09**
Geological and geophysical	**$ 443**	174	614	**$ 1,377**	1,020
Drilling	**109**	11	224	**(261)**	5,218
Completions	**1**	19	282	**285**	215
Total oil and gas additions	**553**	204	1,120	**1,401**	6,453
Office	**–**	50	-	**–**	271
Total expenditures	**553**	$ 254	$ 1,120	**1,401**	$ 6,724
Property disposition	–	–	–	**(2,111)**	–
Total net expenditures	**$ 553**	$ 254	$ 1,120	**$ (710)**	$ 6,724

Tax Pools

Bengal has the following tax pools available to deduct against future earnings:

Years ended March 31 ($000s)	2010	2009
Canada		
Canadian exploration expense	$ 64	$ 64
Canadian development expense	732	522
Canadian oil and gas property expense	–	2,012
Undepreciated capital cost	930	1,299
Canadian foreign exploration & development	2,355	2,625
Non-capital losses carry forward	8,335	5,594
Net capital losses	5,878	5,878
Share issue costs	188	463
Total Canada	18,482	18,457
Australia		
Non-capital losses carry forward	13,890	12,754
Undepreciated capital cost	56	56
Share issue costs	21	50
Total Australia	13,967	12,860
Total	$ 32,449	$ 31,317

No tax benefit has been reflected in the financial statements as the Company does not meet the future earnings test to utilize the pools and realize the benefit.

At March 31, 2010, the Company had approximately $8.3 million and $13.9 million of non-capital losses in Canada and Australia respectively (2009 - $5.6 million and $12.7 million), available to reduce future taxable income. The Canadian losses expire at various dates from March 31, 2011 to 2029. The Australian non-capital losses have no expiry.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. On June 7, 2010 there were 18,237,783 common shares issued and outstanding on a post-consolidation basis.

On July 17, 2008 Avery Resources Inc. consolidated its shares on a 5:1 basis and changed its name to Bengal Energy Ltd.

Subsequent to year end, 41,667 options were exercised on a cashless basis resulting in the issuance of 25,000 common shares and 18,000 options expired.

At June 7, 2010, there were 1,742,333 employee stock options outstanding with an average exercise price of $1.38 per share. Of these, 1,079,339 are exercisable at an average price of $1.64 per share. These options expire between 2010 and 2014 with an average remaining life of 2.9 years.

At June 7, 2010 there are 940,000 common share purchase warrants outstanding of which 627,000 are vested. The warrants entitle the holder to purchase one common share at an exercise price of $2.00 until August 13, 2011.

Trading History	Three Months Ended			Twelve Months Ended	
	03/31/10	03/31/09	12/31/09	03/31/10	03/31/09
High	**$ 1.74**	$ 0.60	$ 1.97	**$ 1.97**	$ 2.90
Low	**1.11**	0.21	0.49	**0.27**	0.21
Close	**$ 1.35**	$ 0.28	$ 1.58	**$ 1.35**	$ 0.28
Volume (000s)	**978**	220	1,301	**3,471**	3,439
Shares outstanding					
Basic and diluted	**18,213**	18,213	18,213	**18,213**	18,213
Weighted average shares outstanding					
Basic and diluted	**18,213**	18,213	18,213	**18,213**	18,212

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2010 the Company had working capital of $1.3 million, including cash and short term deposits of $1.0 million and restricted cash of $0.5 million, compared to working capital of $2.2 million, including cash and short term deposits of $2.7 million, at March 31, 2009. Restricted cash has been released subsequent to year end – see Subsequent events section below. The Company's future capital expenditure plans are discussed below in the "Commitments" section and the "Outlook" section. The Company invests surplus cash only in guaranteed investment certificates.

As the Company does not currently generate sufficient cash flow from operating activities nor have sufficient working capital to fund its operating activities and work commitments, it plans to carry out an equity financing in the range of $5.0 to $10.0 million during the next fiscal year and/or entering into farm-out arrangements to finance its exploration activities as appropriate. The Company's ability to continue as a going concern is dependent upon obtaining the necessary equity financing and/or entering into farm-out arrangements to complete its exploration and development activities and generate profitable operations from its oil and natural gas interests in the future.

Contractual arrangements

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. 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)
Offshore Australia – AC/P47	985km 2D seismic reprocessing & 750km^2 3D seismic	March 2, 2012	$10.3
Offshore Australia – AC/P24	Drill 1 exploration well	Oct 11, 2011	$1.9
Onshore India – CY-ONN-2005/1	500km^2 3D seismic & 3 wells	March 3, 2014	$4.8
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	June 30, 2014(2)	$2.1
Onshore Australia – ATP 752	Drill 2 exploration wells	Dec 31, 2011	$3.0
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$11.0

(1) Translated at March 31, 2010 exchange rate of US $1.00 = CAD $1.02 and AUD $1.00 = CAD $0.94

(2) Based on estimated date of formal signing of PSC with the Government of India. Permit was provisionally awarded in October 2009.

(3) The Company is currently negotiating Native Title Agreement with the Wongkumara People of Queensland. The Native Title Agreement is then submitted to the Government of Queensland for approval and granting of the Authority to Prospect (ATP). Work program consists of 500km of 2D seismic and up to 7 wells.

Bengal is actively seeking joint venture or farm-out partners to finance its exploration commitments under these licenses.

Purchase & Sale Agreement – Onshore Australia Block ATP 732P

On December 10, 2009 Bengal entered into a Purchase & Sale Agreement and upon satisfaction of all conditions in the Agreement, Bengal will be required to pay AUD$1.0 million to acquire a 100% interest in ATP 732P. Upon closing of this acquisition, Bengal will be required to complete a minimum work program consisting of one exploration well and 100km 2D seismic over four years at an estimated cost of $2.5 million.

Bengal's licenses, related work commitments and conditions to the ATP 732P acquisition are discussed further in the "Outlook" section below.

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	$	253	$	126	$	127	$	-	$	-
Asset retirement obligations		158		–		33		10		115
Total contractual obligations	$	411	$	126	$	160	$	10	$	115

RELATED PARTY TRANSACTIONS

The Company paid $100,245 in consulting fees and travel costs to a director of the Company and to a company controlled by the director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At March 31, 2010, the Company has an accounts payable balance of $11,403 (2009 - $nil) payable to this director.

SUBSEQUENT EVENTS

As at March 31, 2010 the Company had a guarantee with the Government of India for US $0.5 million relating to the Company's share of first year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. The guarantee, issued by the Company's bank, was secured by a US $0.5 million term deposit (restricted cash) which was segregated by the bank and not available for general purposes. Subsequent to March 31, 2010 the Canadian Federal Government, through Export Development Canada (EDC), has undertaken to guarantee the obligations of the Company to the bank regarding the guarantee issued on behalf of the Company. Upon receipt of the EDC guarantee, the bank released the Company's restricted cash. Although EDC has guaranteed the current obligations on behalf of the Company, there can be no assurances they will continue to in the future.

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

OUTLOOK

In the past two years Bengal Energy has increased its undeveloped land acreage by 250% to over 2.3 million net acres, with some 87% of this net acreage operated by the Company. Bengal's inventory of producing and prospective oil and natural gas properties in India and Australia range from the Cuisinier light sweet oil discovery in Australia's onshore Cooper Basin where production is expected to come on stream shortly, to high-impact drilling prospects on large blocks offshore India with significant prospectivity.

INDIA

In March 2010, the Company announced that the Government of the State of Tamil Nadu in southern India had granted a formal Petroleum Exploration License on 234,000 acres in India's Cauvery Basin to a consortium including Bengal. Bengal has a 30% interest in the onshore block CY-ONN-2005/1 while the operator, GAIL (India) Limited, holds a 40% interest and the Gujarat State Petroleum Corporation holds the remaining 30% interest. The consortium signed a Production Sharing Contract ("PSC") with the Government of India ("GOI") in December 2008. Exploration work has now commenced on this block. In the first year of the four-year agreement, Bengal and its partners plan to undertake an aggressive exploration campaign consisting initially of acquisition, processing and interpretation of 2,300 km of airborne magnetometry data and reprocessing 1,700 km of existing 2D seismic data. The work program for the first year also includes the planning and commencement of a 3D seismic program, with 250 sq. km. of 3D seismic data acquisition planned in this first year. Bengal's net cost for the first year of exploration activity is budgeted to be US$1,430,000.

Exploratory drilling targets in the block CY-ONN-2005/1 have already been identified from a variety of different play types at drilling depths ranging from 500 to 2,000 metres. Two untested basement highlands cover nearly one-third of the block. These highlands are believed prospective for granite wash oil targets, an established play type in the Cauvery Basin. The existing and additional new exploration targets are anticipated to be mature enough for drilling beginning in 2011. The Indian oil and gas regulatory body, The Directorate General of Hydrocarbons, has reported two new oil discoveries immediately adjacent and northeast of the Cauvery block CY-ONN-2005/1. Such recent discoveries highlight the potential of Bengal's acreage.

In October 2009, the Company announced that its wholly-owned subsidiary, Bengal Energy International Inc, was named the provisional winner of block CY-OSN-2009/1 by India's Directorate General of Hydrocarbons at the New Exploration Licensing Policy bid round in New Delhi, India. This block consists of a 100% working interest in 340,000 offshore acres in India's Cauvery Basin. This was the third significant exploration block awarded to Bengal in a producing basin since late 2008. The Company expects to sign a PSC with the Government of India in June 2010, turning the provisional award of block CY-OSN-2009/1 into a formal agreement, at which time exploration activities will commence.

At CY-OSN-2009/1, Bengal is required to obtain 310 line kilometers of 2D seismic data and 81 square kilometers of 3D seismic data during the first four years of the seven-year exploration phase. The committed work program capital expenditure is estimated at US$2,020,000 (about $6/acre). Drilling will be required to hold the block after the first four years of exploration. A one-time bank guarantee of approximately US$151,500 will be submitted at the time of the signing of the PSC.

AUSTRALIA

Initial production is expected shortly at the Cuisinier oil discovery in Australia's Barta block at ATP 752P. Production facilities have been installed, a production license received, and marketing and transportation contracts are being executed. Processing of the 103 sq km Cuisinier 3D seismic survey is complete and initial interpretations have identified additional exploration and exploitation opportunities for dual objective Hutton/Birkhead and Murta targets. A development plan will be formulated by the Operator upon evaluation of the initial production performance of the Cuisinier discovery well from the Murta geological horizon.

In December 2009, Bengal announced that it had signed an agreement to acquire a 100% working interest in the exploration block ATP 732P. ATP 732P consists of 654,321 gross acres near producing oil and gas fields in Australia's Cooper Basin. The acquisition is subject to the grant of an Authority to Prospect ("ATP") by the government of the state of Queensland in Australia. After reaching a Native Title Agreement with the Boonthamurra People in September 2009, Bengal is now awaiting grant of the ATP from the state government prior to commencing exploration activities. Anticipated expenditures will be approximately AU$1 million over the year following the ATP grant. This grant is expected by the end of fiscal Q2.

Bengal's third new exploration block is at AC/P 47 in the Timor Sea offshore Australia. The Company has a 100% working interest in 861,000 acres on the block and is also the operator. Bengal has budgeted $250,000 for early seismic reprocessing and testing and is collecting all available seismic data records from the associated regulatory agencies. The Company expects to acquire new seismic data during year two of the permit, which ends in March 2011.

Also in Australia, Bengal's joint-venture partner and operator conducted a coal seam test-coring program to evaluate coal seam gas (coal bed methane) potential in the shallow coals of the Cretaceous Winton Formation on PEL 103A in the Cooper Basin. Based on the drilling of two test holes, the coals that were encountered showed low rank and were thin. While the final coal analysis and the resource potential of the coal seam gas in the Winton coals have not yet been determined, early indications suggest that the Winton Formation is likely a sub-economic coal seam gas zone where located within the Innamincka Dome on PEL 103A.

Bengal holds a 10% interest in the offshore Timor Sea Permit AC/P 24, which the Company earned through the drilling of the Katandra-1 oil discovery well in December 2004. The joint-venture partners had earlier decided that any follow-up appraisal drilling would be contingent on the outcome of the pre-stack depth migration processing of the 3D seismic shot over Katandra, which is designed to create a picture of complex underground geological layers. The partners have since received approval from the Northern Territory Government for extension of the permit to October 2011. A decision as to a new exploration well location will be required to satisfy the fifth year's work program commitment beginning in October 2010, and the operator has suggested that drilling should be expected in Q1 or Q2, 2011. The operator's proposed work program is estimated to have a net cost to Bengal of US$1.9 million ending in October 2011. Following the end of the permit term in October 2011, tenure renewal is possible in five-year increments with negotiation of additional work commitments between the operator and the regulatory authority.

In order to accomplish the above, a financing of between $5.0 and $10.0 million will be required in fiscal 2011.

SUMMARY

Bengal's strategy going forward will be to continue to pursue large land positions with operational control, minimal upfront capital requirements, high working interests and strong prospectivity. The Company also continues to review strategic mergers and acquisitions to enhance its portfolio of projects and prospects. Bengal believes its balanced portfolio of exploitation and exploration opportunities in India and Australia position the Company for sustainable long-term growth.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth certain annual information of the Company and has been prepared in accordance with Canadian GAAP.

($000s except per share data and prices)

Year End March 31	**2010**	**2009**	**2008**
Total production volumes (boe/d)	**134**	198	144
Natural gas prices ($/mcf)	**4.00**	7.98	6.95
Oil and liquids prices ($/boe)	**67.05**	100.00	89.21
Total production revenue	**1,772**	4,926	3,574
Net loss	**(4,991)**	(8,198)	(3,645)
Per share – basic and diluted	**(0.27)**	(0.45)	(0.23)
Cash flow from operations	**(1,650)**	1,773	(486)
Per share – basic and diluted	**(0.09)**	0.10	(0.03)
Funds from operations [1]	**(1,566)**	1,105	(193)
Per share – basic and diluted	**(0.08)**	0.06	(0.01)
Total assets	**7,368**	12,664	20,410
Working capital	**1,275**	2,189	8,043

(1) See "Non-GAAP Measurements" on page 4 of this MD&A.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts)	Quarter Ended							
	03/31/10	**12/31/09**	**09/30/09**	**6/30/09**	**3/31/09**	**12/31/08**	**9/30/08**	**6/30/08**
Petroleum and natural gas sales	**$ 280**	**$ 413**	$ 505	$ 574	$ 667	$ 825	$ 1,482	$ 1,952
Cash flow from (used-in) operations	**(493)**	**(264)**	(263)	(630)	(85)	303	1,142	607
Per share Basic and diluted	**(0.03)**	**(0.01)**	(0.01)	(0.03)	(0.00)	0.02	0.06	0.03
Funds from (used in) operations	**(626)**	**(347)**	(295)	(298)	(92)	(29)	367	829
Per share Basic and diluted	**(0.03)**	**(0.02)**	(0.02)	(0.02)	(0.01)	(0.00)	0.02	0.05
Net loss	**$ (1,396)**	**$ (885)**	$(1,848)	$ (865)	$ (839)	$(6,916)	$ (812)	$ (351)
Per share Basic and diluted	**(0.08)**	**(0.05)**	(0.10)	(0.05)	(0.05)	(0.34)	(0.04)	(0.02)
Additions to capital assets, net	**$ 553**	**$ 1,120**	$ (426)	$ 154	$ 254	$ 1,096	$ 3,842	$ 1,532
Working capital	**1,275**	**2,501**	3,970	1,764	2,189	2,642	3,783	7,224
Total assets	**7,368**	**8,928**	9,159	11,839	12,664	13,459	22,812	21,134
Shares outstanding Basic and diluted	**18,213**	**18,213**	18,213	18,213	18,213	18,213	18,213	18,213
Operations								
Average daily production								
Natural gas (Mcf/d)	**377**	**422**	787	684	712	842	609	734
Oil and NGLs (bbls/d)	**12**	**30**	53	58	63	65	84	96
Combined (boe/d)	**75**	**100**	184	172	182	205	186	218
Netback ($/boe)	**$ 18.67**	**$ 21.39**	$ 11.77	$16.78	$14.86	$25.90	$ 49.75	$59.37

Petroleum and natural gas revenues peaked in the three months ended June 30, 2008 due to historically high commodity prices. In addition, production levels were high due to the acquisition of the Oak B.C. gas wells on February 13, 2008 combined with existing Kaybob gas and Toparoa oil production. Gas production volumes continued upward in the quarter ended December 31, 2008 due to commencement of production from the Oak 1-30 well. Since that time, volumes and revenues have been on a declining trend due to natural reservoir declines and lower commodity prices and the sale of the Kaybob gas wells in September, 2009.

In the quarter ended December 31, 2008 the loss is increased by goodwill and ceiling test impairment charges and in the quarter ended September 30, 2009 the net loss was increased by a loss on the disposal of oil and gas assets.

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. Bengal has not identified any embedded derivatives in any of its contracts.

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.

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

Disclosure Controls and Procedures

The Company has established disclosure controls and procedures for the timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the periods specified by applicable securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management and properly reflected in the Company's filings. Consistent with the concept of reasonable assurance, the Company recognizes that the relative cost of maintaining these disclosure controls and procedures should not exceed their expected benefits. As such, the Company's disclosure controls and procedures can only provide reasonable assurance, and not absolute assurance, that the objectives of such controls and procedures are met. 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 in providing reasonable assurance that material information required to be disclosed by the Company in reports filed with the Canadian securities regulators is accurate and complete and filed within the periods required 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 Canadian GAAP. Bengal's management has assessed the design and operating effectiveness of internal controls over financial reporting.

There were no changes in the Company's ICFR in the year ended March 31, 2010 that have materially affected, or are reasonably likely to affect, the Company's ICFR. 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;
- Many of Bengal's information systems are subject to general control deficiencies including a lack of effective controls over spreadsheets, access and documentation. The Company expects that some deficiencies will continue into the future; and

- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advise on complex financial accounting issues and for tax planning, tax provision and compilation of corporate tax returns.

These weaknesses in internal controls over financial reporting result in a more than remote likelihood that a material misstatement would not be prevented or detected. 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 significant accounting policies used by Bengal are disclosed in Note 3 to the audited Consolidated Financial Statements for the years ended March 31, 2010 and 2009. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstance may result in actual results or changes to estimated amounts that differ materially from current estimates. A detailed discussion of the critical accounting policies and practices of the Company helps assess the likelihood of materially different results being reported.

Reserves

Under National Instrument 51-101 ("NI 51-101") "Proved" reserves are defined as those reserves that can be estimated with a high degree of certainty to be recoverable. The level of certainty should result in at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves. It does not mean that there is a 90% probability that the Proved reserves will be recovered; it means there must be at least a 90% probability that the given amount or more will be recovered.

"Proved plus Probable" reserves are the most likely case and are based on a 50% certainty that they will equal or exceed the reserves estimated.

These oil and gas reserve estimates are made using all available geological and reservoir data, as well as historical production data. All of the Company's reserves were evaluated and reported on by an independent qualified reserves evaluator. However, revisions can occur as a result of various factors including: actual reservoir performance, changes in price and cost forecasts or a change in the Company's plans. Reserve changes will impact the financial results as reserves are used to determine the timing of asset retirement obligations, in the calculation of depletion and are used to assess whether asset impairment occurs. Reserve changes also affect other non-GAAP measurements such as finding and development costs; recycle ratios and net asset value calculations. An increase in estimated Proved reserves would result in a reduction in depletion expense.

Depletion and Depreciation

The Company follows the full cost method of accounting for oil and natural gas properties. Under this method, all costs related to the acquisition of, exploration for and development of oil and natural gas reserves are capitalized whether successful or not. Depletion of the capitalized oil and natural gas properties and depreciation of production equipment which includes estimated future development costs less estimated salvage values are calculated using the unit-of-production method, based on production volumes in relation to estimated proven reserves.

Unproved Properties

The cost of the acquisition and evaluation of unproved properties are initially excluded from the depletion calculation. An impairment test is performed on these assets to determine whether the carrying value exceeds the fair value. Any excess in carrying value over fair value is impairment. When Proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs for the calculation of depletion.

Ceiling Test

The ceiling test is a cost recovery test intended to identify and measure potential impairment of assets. An impairment loss is recorded if the sum of the undiscounted cash flows expected from the production of the proved reserves plus the cost, less any impairment, of unproved properties does not exceed the carrying values of the petroleum and natural gas assets. An impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves the cost, less any impairment, of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk free rate. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment as a result of this ceiling test will be charged to operations as additional depletion and depreciation expense.

Asset Retirement Obligations

The Company records a liability for the fair value of legal obligations associated with the retirement of petroleum and natural gas assets in the period incurred. The liability is equal to the discounted fair value of the obligation in the period in which the asset is recorded with an equal offset to the carrying amount of the asset. The liability then accretes with the passage of time and the accretion is recognized as an expense in the financial statements. The total amount of the asset retirement obligation is an estimate based on the Company's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total amount of the estimated cash flows required to settle the asset retirement obligation, the timing of those cash flows and the discount rate used to calculate the present value of those cash flows are all estimates subject to measurement uncertainty. Any change in these estimates would impact the asset retirement liability and the accretion expense.

Income Taxes

The determination of income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. In addition, the Company estimates when its temporary differences are expected to reverse and recognizes its tax assets and liabilities based on the legislated tax rate in those periods. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Stock-Based Compensation

The Company applies the fair value method for valuing stock option grants and warrants. This method requires the Company to make estimates of expected stock volatility, the expected hold period prior to exercising options, expected forfeitures of options and expected dividends to be declared by the Company. The stock-based compensation expense will not represent the actual fair value received by the optionees or the warrant holders as the fair value is estimated at the time of grant and is not adjusted. Due to the time period and the number of estimates involved, it is likely that the actual value of the options and warrants will differ materially from what has been recorded in the financial statements.

Goodwill

The process of accounting for the purchase of a company results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over the fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. Goodwill is assessed periodically for impairment. Impairment is indicated if the fair value of the Company falls below the book value of its equity.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates, including estimates of revenues, royalties and operating costs as at a specific reporting date, but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in progress or recently completed where actual costs have not been received by the reporting date. The Company obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

FINANCIAL REPORTING UPDATE

International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board ("AcSB") confirmed the changeover to IFRS from Canadian Generally Accepted Accounting Principles ("GAAP") will be required for publicly accountable enterprises for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010.

In response, the Company has completed its high-level IFRS changeover plan and established a preliminary timeline for the execution and completion of the conversion project. The changeover plan was determined following a preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company.

During the next phase of the project, the Company is performing an in-depth review of the significant areas of difference identified during the preliminary assessment, in order to identify all specific Canadian GAAP and IFRS differences and select ongoing IFRS policies. Key areas addressed will also be reviewed to determine any information technology issues, the impact on internal controls over financial reporting and the impact on business activities including the effect, if any, on compensation arrangements. External advisors have been consulted and will assist with the project on an as needed basis to ensure IFRS readiness by April 1, 2011 which is the Company's first fiscal year beginning after January 1, 2011.

Below is a summary of the Company's preliminary views of the key areas where changes in accounting policies are expected that may impact the Company's consolidated financial statements. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. It is intended to highlight those areas the Company believes to be most significant; however, analysis of changes is still in progress and not all decisions have been made where choices of accounting policies are available. At this stage, the Company has not quantified the impacts expected on its consolidated financial statements for these differences.

Note that most adjustments required on transition to IFRS will be made retrospectively, against opening retained earnings in the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated because they are applied prospectively will only be made as of the first day of the year of transition

IFRS 1 "First-Time Adoption of International Financial Reporting Standards" provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The Company is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate in the Company's circumstances.

Property, Plant and Equipment. International Accounting Standard (IAS) 16 "Property, Plant & Equipment" and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. There will be more depreciable components than the current single full cost pool. IFRS also permits property, plant and equipment to be measured using the fair value model or the historical cost model. The Company in not planning on adopting the fair value measurement model for property, plant and equipment.

IFRS 1 contains an exemption where by a company may apply IFRS prospectively by utilizing its current reserves (volumes or values) at the transition date to allocate the Company's full cost pool, with the provision that an impairment test, under IFRS standards, be conducted at the transition date. The Company intends to use this exemption and is currently evaluating the impact of allocating the net book value based on reserve volumes or values.

Impairment of Assets. IAS 36 "Impairment of Assets" requires that impairments be determined based on discounted cash flows Impairment tests are based on the fair value of the assets less costs to sell or value in use. This differs from the current two step practice where the asset's carrying value is initially compared to the estimated undiscounted future cash flows, and only if the carrying value exceeds the undiscounted future cash flows is a discounted analysis, step two, required. There is no undiscounted test under IFRS. This may result in more frequent write-downs upon transition.

In addition, under IFRS, an entity must also evaluate whether there are changes in circumstances that would support an impairment reversal, which is not allowable under GAAP.

Another difference arises in the level at which an impairment test is performed. Under IFRS, impairment testing will be performed on cash generating units. The Company has begun the process of identifying its cash generating units. There is likely to be more cash generating units than the current country-by-country full cost centres.

Provisions. Another key difference to Bengal will be the accounting for Asset Retirement Obligations ("ARO"). Under IFRS, the ARO or a decommissioning liability provision as referred to in IFRS is likely to increase as a result of the change from a credit adjusted risk free rate to a risk free rate (government bond) in the discounting of the cash flows. In addition, any change in the discount rate would affect the entire liability and not just the current additions. The accretion expense will also now be a finance cost in the Income Statement rather than being part of DD&A.

Also, under IFRS – Stock Based Compensation, our options that vest in three installments must be accounted for as though each installment is a separate option issue. This will result in front end loading of compensation expense. In addition, an estimate of forfeitures must be taken into consideration in the expense.

Throughout fiscal 2011, the Company will continue to document and define its IFRS accounting policies and the Company will start to evaluate the financial impact of IFRS on its financial statements. Staff training programs have continued in fiscal 2010 and will be ongoing as the project unfolds.

The Company will also continue to monitor standards development as issued by the International Accounting Standards Board ("IASB") and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

Business combinations consolidated financial statements and non-controlling interest

In December 2008, the CICA issued Section 1582, Business Combinations. This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company.

In 2009 Section 1601 and Section 1602 were issued which replace the existing guidance under section 1600, Consolidated Financial Statements. These standards provide guidance for preparing consolidated financial statements and for accounting for non-controlling interest in a subsidiary.

All three standards are effective for the Company commencing on April 1, 2011 at which time the Company will have adopted IFRS. Early adoption is permitted; however, the early adoption of one of these standards would require adoption of the other two standards.

RISK FACTORS

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

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

Exploration, Development and Production Risks

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

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

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

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

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

Risks Associated with Foreign Operations

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

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

Substantial Capital Requirements and Liquidity

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

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

Health, Safety and Environment

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

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

Insurance

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

Competition

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

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

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd, 1140, 715 - 5 Avenue S.W., Calgary, Alberta T2P 2X6, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S RESPONSIBILITY STATEMENT

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information that is publicly disclosed. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting policies and include estimates and assumptions based on management's best judgment. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. Independent auditors appointed by the shareholders have examined the consolidated financial statements. Their report is presented below. The Audit Committee, consisting of independent members of the Board of Directors, have reviewed the consolidated financial statements with management and the independent auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

Bradley Johnson
Chief Executive Officer

Bryan Goudie
Chief Financial Officer

Calgary, Alberta
June 7, 2010

Bengal Energy Ltd.

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Bengal Energy Ltd. as at March 31, 2010 and 2009 and the consolidated statements of operations, comprehensive loss and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at March 31, 2010 and 2009 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
June 7, 2010

BENGAL ENERGY LTD.

CONSOLIDATED BALANCE SHEETS

(thousands of dollars)

As at March 31,	2010	2009
ASSETS		
Current assets:		
Cash and short-term deposits	$ 1,055	$ 2,676
Restricted cash (Note 6)	510	–
Accounts receivable	273	835
Prepaid expenses and deposits	103	118
	1,941	3,629
Petroleum and natural gas properties (Note 5)	5,427	9,035
	$ 7,368	$ 12,664
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 666	$ 1,440
Asset retirement obligations (Note 7)	93	179
Shareholders' equity:		
Share capital (Note 9)	43,460	43,460
Warrants (Note 9)	490	229
Contributed surplus (Note 9)	3,871	3,577
Deficit	(41,212)	(36,221)
	6,609	11,045
	$ 7,368	$ 12,664

Going concern (Note 2)
Commitment (Note 13)
Subsequent events (15)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Bradley Johnson

Director
Bradley G. Johnson

JBHowe

Director
James B. Howe

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF OPERATIONS, COMPREHENSIVE LOSS AND DEFICIT

(thousands of dollars, except per share amounts)

Years ended March 31,		**2010**		**2009**
Revenues				
Petroleum and natural gas	$	1,772	$	4,926
Royalties		(231)		(882)
Interest		20		162
		1,561		4,206
Expenses				
General and administrative		2,431		2,247
Operating and transportation		756		1,145
Depletion, depreciation and accretion (Note 5)		1,892		7,036
Loss on sale of oil and gas properties (Note 5)		943		–
Stock-based compensation (Note 9)		555		434
Goodwill impairment (Note 3-L)		–		1,759
Foreign exchange gain		(25)		(208)
		6,552		12,413
Loss before non-controlling interest		(4,991)		(8,207)
Non-controlling interest		–		9
Net loss and comprehensive loss		(4,991)		(8,198)
Deficit, beginning of year		(36,221)		(28,023)
Deficit, end of year	$	(41,212)	$	(36,221)
Weighted average number of shares outstanding (000s) (Note 9)		18,213		18,212
Basic and diluted loss per share (Note 9)	$	(0.27)	$	(0.45)

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars)

Years ended March 31,		2010		2009
Cash provided by (used in):				
Operations				
Net loss	$	(4,991)	$	(8,198)
Items not affecting cash				
Depletion, depreciation and accretion		1,892		7,036
Loss on sale of oil and gas assets		943		–
Stock-based compensation		555		434
Goodwill impairment		–		1,759
Unrealized foreign exchange loss		35		74
Abandonment expenditures		(21)		(12)
Changes in non-cash working capital (Note 12)		(63)		680
Cash flow from (used in) operations		(1,650)		1,773
Financing				
Exercise of stock options		–		22
Changes in non-cash working capital (Note 12)		5		(60)
Cash flow from (used in) financing		5		(38)
Investments				
Additions to petroleum and natural gas properties		(1,401)		(6,724)
Property disposition (Note 5)		2,111		–
Increase in restricted cash		(510)		–
Changes in non-cash working capital (Note 12)		(139)		(80)
Cash flow from (used in) investing		61		(6,804)
Foreign exchange loss on cash and short-term deposits		(37)		(107)
Decrease in cash and short-term deposits		(1,621)		(5,176)
Cash and short-term deposits, beginning of year		2,676		7,852
Cash and short-term deposits, end of year	$	1,055	$	2,676

		2010		2009
Interest received	$	26	$	203
Taxes paid	$	–	$	–

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

Notes to Consolidated Financial Statements

Years ended March 31, 2010 and 2009
(Tabular amounts are stated in thousands of dollars except share and per share amounts)

1. INCORPORATION:

Bengal Energy Ltd (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration for and development of oil and gas reserves in Australia, India and Canada.

2. GOING CONCERN:

The Company's ability to continue as a going concern is dependent upon obtaining the necessary financing to complete its exploration and development activities and generate profitable operations from its oil and natural gas interests in the future. The Company incurred a net loss of $5.0 million for the year ended March 31, 2010 and had an accumulated deficit of $41.2 million as at March 31, 2010. Management regularly monitors funding requirements along with the Company's asset portfolio, operational activities, and market conditions to ensure they are appropriately balanced by either revising the Company's financing plans, making changes to operational activities, realizing assets or raising capital as required. In the event that the Company is unable to make the future work commitment payments on certain of its permits (see note 13), the Company's existing capital investment on those permits of $563,000 in India and $611,000 in Australia may be forfeited leading to a potential impairment loss in the consolidated financial statements.

The Company's financial statements as of and for the year ended March 31, 2010 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities and commitments in the normal course of business. Should the going concern assumption not be appropriate, certain asset and liability amounts would require adjustment and reclassification which may be material.

3. SIGNIFICANT ACCOUNTING POLICES:

The consolidated financial statements of Bengal have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

(a) Principles of consolidation:

These consolidated financial statements include the accounts of the Company and its wholly and majority owned subsidiaries, Avery Resources Australia (Pty) Ltd., Bengal Energy International Inc., Avery Resources (Northern Ireland) Ltd. and Northstar Energy Pty Ltd. respectively. All inter-entity transactions and balances have been eliminated.

(b) Cash and cash equivalents:

Cash and cash equivalents are comprised of cash and all investments with an original maturity date of three months or less.

(c) Petroleum and natural gas properties:

(i) Capitalized costs:

The full cost method of accounting is followed for petroleum and natural gas properties whereby all costs relating to the acquisition of, exploration for and development of petroleum and natural gas reserves are capitalized into a cost centre for each respective country in which the Company has operations. Such costs include lease acquisitions, geological and geophysical activities, lease rentals on undeveloped properties, the drilling of productive and non-productive wells, and administration expenses directly related to the acquisition, exploration and development activities.

(ii) Depletion and depreciation:

Total capitalized costs in each cost centre are depleted and depreciated using the unit of production method based on the Company's share of estimated gross proved oil and gas reserves as determined by independent reservoir engineers. For purposes of the depletion and depreciation calculation, proved oil and gas reserves are converted to a common unit of measure on the basis of their approximate relative energy content.

The carrying value of unproved properties, including the cost of remote exploratory test wells, is initially excluded from the depletion calculation. When proved reserves are assigned or a property is considered to be impaired, the cost of the property or the amount of the impairment will be added to the capitalized costs subject to depletion and depreciation.

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized except where the sale results in a change in the rate of depletion and depreciation by 20% or more.

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

(iii) Ceiling test:

Petroleum and natural gas assets in each cost centre are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amounts are assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the cost of unproved properties and major development projects, less any impairment, exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the cost of unproved properties and major development projects, less any impairments, of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(d) Asset retirement obligations:

The fair value of an asset retirement obligation is recognized in the period in which it is incurred when a reasonable estimate of fair value can be made. The fair value is based on estimated reserve life, inflation and discount rates. The provision is recorded as a long-term liability, with a corresponding increase in the carrying value of the associated asset. The capitalized amount is depleted on a unit-of-production basis. Subsequent to the initial measurement of the asset retirement obligations the obligations are adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and charged to net loss for the year. The liability amount is decreased for actual abandonment costs incurred.

(e) Foreign currency translation:

The Company translates the accounts of its Australian, Indian and Irish subsidiaries, which are considered to be integrated, using the temporal method whereby monetary assets and liabilities are translated at the rates of exchange at the balance sheet dates, non-monetary assets and liabilities are translated at the rates in effect at the dates the assets or liabilities were acquired and revenues and expenses are translated at the average rates of exchange during the month in which they are recognized. Resulting gains or losses are included in earnings.

(f) Stock-based compensation plans:

The Company uses the fair value method of accounting for stock option grants and warrants. At the date of the grant or issue, the fair value of the stock options and warrants is estimated. This fair value of the options is recorded as an expense over the vesting period of the option and warrants with a corresponding increase to contributed surplus and warrants respectively. In determining the fair value of the stock options and warrants granted, the Black-Scholes option pricing model is used and assumptions regarding interest rates, underlying volatility of the Company's stock and expected life of the options and warrants are made. Upon the exercise of stock options or warrants, consideration received together with the amount previously recognized in contributed surplus or warrants is recorded as an increase to share capital.

(g) Per share amounts:

Basic per share amounts are computed by dividing net earnings (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.

(h) Income taxes:

The Company uses the asset and liability method of tax allocation accounting. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the enacted or substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

(i) Revenue recognition:

Revenues from the sale of natural gas, natural gas liquids and crude oil owned by the Company are recognized when title passes from the Company to its customers.

(j) Joint operations:

Significant portions of the Company's oil and gas activities are conducted jointly with others and accordingly, these financial statements reflect only the Company's interest in such activities.

(k) Financial Instruments:

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents and restricted cash as held for trading, which are measured at fair value. Accounts receivable are classified as loans and receivables, which are measured at amortized cost. This is determined using the effective interest method. Accounts payable and accrued liabilities are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method.

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.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company immediately expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability.

(l) Goodwill:

The process of accounting for the purchase of a company results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over the fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. Goodwill is assessed periodically for impairment. Impairment is indicated if the fair value of the Company falls below the book value of its equity.

In fiscal 2009, the Company recognized a goodwill impairment of $1,759,000 due to the economic conditions and declines in the Company's share price at that time.

4. CHANGES IN ACCOUNTING POLICIES

Effective March 31, 2010, the Company adopted the CICA amended Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making fair value measurements. Fair value of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. The adoption did not impact the measurement of the amounts reported in the Company's financial statements as they relate to disclosures as further outlined on Note 10.

Future Accounting Changes

Business combinations, consolidated financial statements and non-controlling interest:

In December 2008, the CICA issued Section 1582, Business Combinations. This section is effective January 1, 2011 and applies prospectively to business combinations for which the acquisition date is on or after the first annual reporting period beginning on or after January 1, 2011 for the Company.

In 2009 Section 1601 and Section 1602 were issued which replace the existing guidance under section 1600, Consolidated Financial Statements. These standards provide guidance for preparing consolidated financial statements and for accounting for non-controlling interest in a subsidiary.

All three standards are effective for the Company commencing on April 1, 2011 at which time the Company will have adopted IFRS. Early adoption is permitted; however, the early adoption of one of these standards would require adoption of the other two standards.

5. PETROLEUM AND NATURAL GAS PROPERTIES

($000s)	Cost	Accumulated Depletion & Depreciation	Net Book Value
March 31, 2010			
Australia			
Petroleum and natural gas properties	$ 18,986	$ 15,575	$ 3,411
Other assets	56	53	3
Canada			
Petroleum and natural gas properties	4,257	3,003	1,254
Other assets	525	329	196
New cost centres (India and Ireland)			
Petroleum properties – India	563	–	563
Petroleum properties - Ireland	451	451	–
	$ 24,838	$ 19,411	$ 5,427
March 31, 2009			
Australia			
Petroleum and natural gas properties	$ 18,389	$ 15,057	$ 3,332
Other assets	56	39	17
Canada			
Petroleum and natural gas properties	6,796	2,176	4,620
Other assets	525	260	265
New cost centres (India and Ireland)			
Petroleum properties – India	364	–	364
Petroleum properties - Ireland	437	–	437
	$ 26,567	$ 17,532	$ 9,035

At March 31, 2010, undeveloped property costs of $3.0 million (2009 - $2.3 million) related to Australia have been excluded from the full cost pool for the depletion calculation.

Future development costs of proved, undeveloped reserves of $0.1 million (2009 – $0.1 million) are included in the depletion calculation.

At March 31, 2010 the new cost centre (India) was considered to be in the preproduction stage and costs of $0.5 million (2009 – $0.8 million for India and Ireland) have also been excluded from the full cost pool for the depletion calculation.

Major uncertainties affect the recoverability of these costs as the recovery of the costs noted above is dependent on the Corporation obtaining licenses in certain instances, discovery of adequate commercial reserves and achieving commercial production or sale.

Property Disposition

On September 24, 2009, the Company disposed of interests in certain Canadian petroleum and natural gas assets for $2,111,000, net of purchase price adjustments. The disposition also resulted in the removal of $63,000 of assets retirement obligations. The disposition of assets resulted in a change greater than 20% in the depletion rate in the Canadian cost centre and, as a result, a loss of $943,000 has been charged to net loss for the year.

Unproved Property Impairment

At March 31, 2010, the Company recorded an unproved property impairment charge of $0.5 million pertaining to its South Larne permit in Northern Ireland. The exploration license for the permit has expired and the Company does not expect any future activity on the permit.

Ceiling Test

No impairment was recognized under the ceiling test at March 31, 2010 (2009 - $3.1 million included in DD&A expense). The prices used in the ceiling test at March 31, 2010 were from the Degolyer and MacNaughton Canada Limited Price Forecast as of March 31, 2010, adjusted for differentials specific to the Company's reserves, and is as follows:

	2010	2011	2012	2013	2014	Percent increase per year to 2020
WTI Cushing Oklahoma ($U.S./bbl)	$ 80.00	$ 83.89	$ 86.35	$ 89.14	$ 92.01	~ 3.0%
Edmonton Par Price 40° API ($Cdn/bbl)	$ 83.73	$ 87.82	$ 90.40	$ 93.32	$ 96.33	~ 3.5%
Alberta Plantgate - Spot ($Cdn/mcf)	$ 4.18	$ 5.07	$ 5.59	$ 6.43	$ 6.88	~ 13.3%
Tapis ($Cdn/bbl)	$ 89.47	$ 93.58	$ 96.16	$ 99.09	$ 102.12	~ 2.5%

6. RESTRICTED CASH

As at March 31, 2010, the Company had a US $0.5 million performance guarantee issued by a bank in India to the Government of India to guarantee the Company's share of first year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. The Company's Canadian bank has provided a guarantee to the bank in India on behalf of the Company. The Canadian bank guarantee is secured by a US $0.5 million term deposit which is segregated by the bank and not available for general purposes. See subsequent events note discussing the release of this restricted cash.

7. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from ownership interests in petroleum and natural gas assets. The Company estimates the total inflation adjusted undiscounted amount of cash flow required to settle its asset retirement obligations at March 31, 2010 is approximately $158,000 (March 31, 2009 - $301,000) which will be incurred between 2011 and 2024. An inflation factor of 2% has been applied to the estimated asset retirement cost at March 31, 2010 and 2009. A credit-adjusted risk-free rate of between 7% and 10% was used to calculate the initial fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

($000s)	2010	2009
Balance, beginning of period	$ 179	$ 180
Revisions	(14)	(17)
Liabilities settled	(21)	(12)
Liabilities incurred	–	16
Liabilities disposed	(63)	–
Accretion	12	12
Balance, end of period	$ 93	$ 179

8. 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)	2010	2009
Loss before taxes	$ 4,991	$ 8,198
Statutory tax rate	28.75%	29.38%
Expected income tax benefit	$ 1,435	$ 2,409
Non-deductible Goodwill impairment	–	(517)
Foreign exchange	(265)	–
Stock-based compensation	(160)	(127)
Effect of tax rate changes and other	(56)	(264)
	954	1,501
Change in valuation allowance	(954)	(1,501)
Income tax expense	$ –	$ –

The components of the net future income tax assets (liabilities) are as follows:

As of March 31 ($000s)	2010	2009
Future income tax assets:		
Non-capital losses	$ 6,251	$ 5,223
Net capital losses	1,469	1,469
Petroleum and natural gas properties and equipment	(395)	(686)
Share issue costs	53	131
Foreign exchange	(265)	–
Asset retirement obligations	24	46
Future income tax assets	7,137	6,183
Valuation allowance	(7,137)	(6,183)
Net future tax asset	$ –	$ –

At March 31, 2010, the Company had approximately $8.3 million and $13.9 million of non-capital losses in Canada and Australia respectively (2009 - $5.6 million and $12.7 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2011 to 2029. The Australian non-capital losses have no expiry.

9. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares.

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

(b) Issued (number of shares adjusted for 5:1 consolidation):

($000s)	Number of shares		Amount
Balance March 31, 2008	**18,197,783**	**$**	**43,438**
Issued on exercise of stock options	15,000		22
Balance March 31, 2009 and 2010	**18,212,783**	$	43,460

Stock Consolidation

On July 17, 2008, the Company's shareholders approved the consolidation of the Company's shares on a 5:1 basis and the change of the Company's name from Avery Resources Inc. to Bengal Energy Ltd., effective on the close of business July 21, 2008. The effect of the one-for-five consolidation was to reduce to one-fifth the number of common shares, warrants and stock options outstanding as of the close of business on July 21, 2008. In addition, the weighted average exercise prices and fair value per option and warrant were adjusted to five times the pre-consolidation prices. All information included in these financial statements is calculated and presented subsequent to the one-for-five consolidation.

(c) Stock-based compensation - warrants:

On February 13, 2008 Bengal issued 940,000 common share purchase warrants in exchange for 1,807,692 Bengal Energy Inc. common share purchase warrants as part of the acquisition of Bengal Energy Inc. Each Bengal warrant shall vest and be exercisable as to one-third of the warrants on each of the first, second and third anniversaries of issuance or immediately upon the 20-day weighted average trading price of the Bengal shares being $4.00 per share and upon vesting shall entitle the holder to acquire one Bengal share at an exercise price of $2.00 until August 13, 2011.

The fair value of the warrants issued February 13, 2008 was estimated to be $0.7 million using the Black-Scholes option pricing model and will be recorded in warrant capital and compensation expense over the 36 month vesting period of the warrants.

The table below provides details of common share purchase warrant activity (adjusted for 5:1 share consolidation):

($000s)	Number of Warrants		Amount
Balance March 31, 2008	**940,000**	**$**	**31**
Stock-based compensation expense	-		198
Balance March 31, 2009	**940,000**	**$**	**229**
Stock-based compensation expense	-		261
Balance March 31, 2010	**940,000**	**$**	**490**

(d) Stock-based compensation – stock options:

The Company has a stock option plan for directors, officers, employees and consultants of the Company whereby stock options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Stock 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.

Bengal accounts for its stock-based compensation plan using the fair value method. Under this method, a compensation cost is charged over the vesting period and results in one-third of the fair value of the options being charged to earnings immediately at the time of grant and one-third of the fair value is charged to earnings on each of the next two anniversaries after the grant date. 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.

Bengal has not incorporated an estimated forfeiture rate for stock options that will not vest, rather the Company accounts for actual forfeitures as they occur.

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at March 31, 2008	**1,142,373**	**$ 2.90**
Granted	685,000	0.36
Exercised	(15,000)	1.50
Expired	(16,007)	2.08
Forfeited	(231,000)	2.82
Outstanding at March 31, 2009	**1,565,366**	**$ 1.81**
Granted	652,000	1.26
Expired	(405,366)	2.92
Forfeited	(10,000)	1.60
Outstanding at March 31, 2010	**1,802,000**	**$ 1.37**
Exercisable at March 31, 2010	1,139,005	$ 1.61

	Options Outstanding			Options Exercisable	
Option Price (1)	Number Outstanding	Exercise Price (2)	Remaining Life (3)	Number Exercisable	Exercise Price (2)
$ 0.36	685,000	$ 0.36	4.0	456,670	$ 0.36
$ 1.26–2.25	805,000	$ 1.41	2.5	370,335	$ 1.57
$ 2.26–3.25	140,000	$ 3.15	1.7	140,000	$ 3.15
$ 3.26–4.50	172,000	$ 3.74	1.2	172,000	$ 3.74
Total	**1,802,000**	**$ 1.37**	**2.9**	**1,139,005**	**$ 1.61**

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

The Company recorded stock-based compensation expense of $0.3 million (2009 - $0.2 million) for the year ended March 31, 2010. At March 31, 2010 there is $0.4 million of stock-based compensation remaining to be amortized over the next two 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:

	2010	2009
Assumptions:		
Risk free interest rate (%)	2.0%	2.0%
Expected life (years)	3 yr	5 yr
Expected volatility (%)	122%	60%
Vesting period (years)	2 yr	2 yr
Results:		
Weighted average fair value of options granted	$ 0.91	$ 0.19

The fair value of stock options granted during the year ended March 31, 2010 was estimated to be $0.6 million (2009 - $0.1 million).

(e) Contributed surplus

A reconciliation of contributed surplus is provided below:

($000s) **Years ended March 31**	**2010**	**2009**
Balance, beginning of period	**$ 3,577**	**$ 3,341**
Stock-based compensation expense	294	236
Balance, end of period	**$ 3,871**	**$ 3,577**

(f) Per share amounts:

Per share amounts are calculated using losses and the weighted-average number of common shares outstanding. The Company has recorded a loss in each of the last two years and therefore any addition to basic shares outstanding is anti-dilutive.

The weighted average number of shares outstanding for the year ended March 31, 2010 is 18,212,783 (2009 – 18,211,883).

At March 31, 2010, there were 1,802,000 (2009 – 1,565,366) options that were anti-dilutive and at March 31, 2010 there were also 940,000 warrants (2009 – 940,000) that were anti-dilutive.

10. 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, policies and processes for measuring and managing risk, and the Company’s management of capital. Further quantitative disclosures are included throughout these financial statements.

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 and short-term deposits, restricted cash, 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.

(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, 2010, Bengal's receivables consisted of $0.1 million (2009 - $0.4 million) from joint venture partners, $nil (2009 - $0.1 million) of receivables from petroleum and natural gas marketers and $0.2 million (2009 - $0.3 million) of other trade receivables.

In Canada, production from the Oak property is marketed by the operator. Bengal has not experienced any collection issues with the operator of the Oak wells.

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, 2010, the Company had no receivables that were considered past due (past due is considered greater than 90 days outstanding).

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, 2010 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended March 31, 2010 or 2009.

Cash and short-term deposits, 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 and accrued liabilities and amounted to $0.7 million at March 31, 2010. Bengal had $1.1 million in cash, $0.5 million in restricted cash and a net working capital surplus of $1.3 million at March 31, 2010.

As the Company is in the early stages of exploration and development, and although it is generating operating revenue, funding of most activities to date has been supplemented through the issuance of share capital. It is expected that further equity financings, as well as joint ventures and farm-ins when appropriate, will be used to fund ongoing operations and the Company's projected capital program, supplemented by cash flow from operations, working capital and debt, when the level of operations provides borrowing capacity.

(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 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 had no forward exchange rate contracts in place as at March 31, 2010.

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, 2010 ($000s)				
	Total	**CAD**	**AUD**	**U.S.D**
			CAD $ Equivalent	
Cash and short-term deposits	1,055	499	417	139
Restricted cash	510	–	–	510
Accounts receivable	273	224	24	25
Accounts payable and accrued liabilities	(666)	(345)	(321)	–
Balance sheet exposure	1,172	378	120	674

A 5% strengthening or weakening of the CAD as compared to the AUD or USD would have no material impact on net loss.

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 Tapis reference price, which tracks WTI but is also affected by refinery capacity in South East Asia and the U.S. There were no financial instruments in place to manage commodity prices during the period ended March 31, 2010. At March 31, 2010 a $5.00 decrease in oil prices and a $0.50 decline in natural gas prices would have caused net loss to increase by $150,000 for the 2010 fiscal year.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its cash and cash equivalents that have a floating interest rate. The Company is only receiving one quarter of 1% interest on its guaranteed investment certificates. If interest rates declined from 0.25% to zero, there would have been a $20,000 decrease to earnings and cash flow in the year ended March 31, 2010 and a 1% increase in interest rates would increase earnings and cash flow by $65,000 over the same period. The Company had no interest rate swaps or hedges at March 31, 2010.

11. 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. The Company currently has no debt.

In order to maintain or adjust the capital structure, the Company may from time to time issue shares (if available on reasonable terms), 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.

12. CHANGES IN NON-CASH WORKING CAPITAL

Years Ended March 31 ($000s)	2010	2009
Accounts receivable	$ 562	$ 646
Prepaid expenses and deposits	15	26
Accounts payable and accrued liabilities	(774)	(132)
Total	$ (197)	$ 540
Relating to:		
Operating	$ (63)	$ 680
Financing	5	(60)
Investing	(139)	(80)
Total	$ (197)	$ 540

13. COMMITMENT

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. 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)
Offshore Australia – AC/P47	985km 2D seismic reprocessing & 750km^2 3D seismic	March 2, 2012	$10.3
Offshore Australia – AC/P24	Drill 1 exploration well	Oct 11, 2011	$1.9
Onshore India – CY-ONN-2005/1	500km^2 3D seismic & 3 wells	March 3, 2014	$4.8

Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	June 30, 2014[(2)]	$2.1
Onshore Australia – ATP 752	Drill 2 exploration wells	December 31, 2011	$3.0
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP[(3)]	4 years after grant of ATP	$11.0

[(1)] Translated at March 31, 2010 exchange rate of US $1.00 = CAD $1.02 and AUD $1.00 = CAD $0.94

[(2)] Based on estimated date of formal signing of PSC with the Government of India. Permit was provisionally awarded in October 2009.

[(3)] Currently negotiating Native Title Agreement with the Wongkumara People of Queensland. The Native Title Agreement is then submitted to the Government of Queensland for approval and granting of the Authority to Prospect ("ATP"). Work program consists of 500km of 2D seismic and up to 7 wells.

Bengal is pursuing joint venture or farm-out arrangements to finance its exploration commitments under some of these licenses.

Purchase & Sale Agreement – Onshore Australia Block ATP 732P

On December 10, 2009 Bengal entered into a Purchase & Sale Agreement and upon satisfaction of all conditions in the Agreement, Bengal will be required to pay AUD$1.0 million to acquire 100% interest in ATP 732P. Upon closing of this acquisition, Bengal will be required to complete a minimum work program consisting of one exploration well and 100km 2D seismic over four years at an estimated cost of $2.5 million.

At March 31, 2010 the Company had the following lease commitment for office space in Canada:

($000s)		
Fiscal 2011 – April 2010 to March 2011	$	126
Fiscal 2012 – April 2011 to March 2012		127
		253

14. RELATED PARTY TRANSACTIONS

The Company paid $100,245 in consulting fees and travel costs to a director of the Company and to a company controlled by a director. The fees were paid in the ordinary course of business based on market rates and were for international consulting services. At March 31, 2010, the Company has an accounts payable balance of $11,403 (2009 - $nil) payable to this director.

15. SUBSEQUENT EVENTS

As at March 31, 2010 the Company had a guarantee with the Government of India for US $0.5 million relating to the Company's share of first year exploration expenditures on its onshore Cauvery Block CY-ONN-2005/1. The guarantee, issued by the Company's bank, was secured by a US $0.5 million term deposit (restricted cash) which was segregated by the bank and not available for general purposes. Subsequent to March 31, 2010 the Canadian Federal Government, through Export Development Canada (EDC), has undertaken to guarantee the obligations of the Company to the bank regarding the guarantee issued on behalf of the Company. Upon receipt of the EDC guarantee, the bank released the Company's restricted cash. Although EDC has guaranteed the current obligations on behalf of the Company, there can be no assurances they will continue to in the future.

16. SEGMENTED INFORMATION

Year ended Mar 31, 2010 ($000s)	Australia	Canada	Other[1]	Total
Revenue, net of royalties	$ 706	$ 835	$ –	$ 1,541
Net loss	(614)	(4,174)	(203)	(4,991)
Petroleum and natural gas property expenditures	$ 597	$ 591	$ 213	$ 1,401
Property disposition	$ -	$ 2,111	$ -	$ 2,111

As at Mar 31, 2010 ($000s)				
Petroleum and natural gas properties				
Cost	$ 19,042	$ 4,782	$ 1,014	$ 24,838
Accumulated depletion, depreciation and accretion	(15,628)	(3,332)	(451)	(19,411)
Net book value	$ 3,414	$ 1,450	$ 563	$ 5,427

(1) Other is new cost centres considered to be in the pre-production stage and includes India.

Year ended Mar 31, 2009 ($000s)	Australia	Canada	Other[2]	Total
Revenue, net of royalties	$ 2,093	$ 1,951	$ –	$ 4,044
Net loss	(4,757)	(3,342)	(99)	(8,198)
Petroleum and natural gas property expenditures	$ 5,415	$ 841	$ 468	$ 6,724
Property disposition	$ -	$ -	$ -	$ -

As at Mar 31, 2009 ($000s)				
Petroleum and natural gas properties				
Cost	$ 18,445	$ 7,321	$ 801	$ 26,567
Accumulated depletion, depreciation and accretion	(15,096)	(2,436)	–	(17,532)
Net book value	$ 3,349	$ 4,885	$ 801	$ 9,035

(2) Other is new cost centres considered to be in the pre-production stage and includes India and Ireland.

CORPORATE INFORMATION

AUDITORS
KPMG LLP • Calgary, Canada

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

BANKERS
Royal Bank of Canada • Calgary, Canada
West Pac Bank • Brisbane, Australia
Commonwealth Bank • Brisbane, Australia

REGISTRAR AND TRANSFER AGENT
Valiant Trust Corporation • Calgary, Canada

INVESTOR RELATIONS
Bryan Mills Iradesso • Calgary, Canada

DIRECTORS
Chayan Chakrabarty
Richard N. Edgar
Edwin (Ted) S. Hanbury
James B. Howe
Bradley G. Johnson
Ian J. Towers

GOVERNANCE AND DISCLOSURE COMMITTEE
All Directors are members of the Committee

AUDIT COMMITTEE
Richard Edgar
James B. Howe
Ian J. Towers

RESERVES COMMITTEE
Richard Edgar
Edwin (Ted) S. Hanbury
Ian J. Towers

COMPENSATION COMMITTEE
Richard Edgar
Edwin (Ted) S. Hanbury
Ian J. Towers

OFFICERS
Bradley G. Johnson, Chief Executive Officer
Chayan Chakrabarty, President
James Mott, Vice President, Exploration
Bryan C. Goudie, Chief Financial Officer
Bruce Allford, Secretary

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