Appraisal and Exploration Drilling with High-Impact Upside

Bengal Energy Ltd.

Annual Report | 2012

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MESSAGE TO SHAREHOLDERS

We achieved our most active year to date in fiscal 2012 with production from our Cuisinier light oil discovery and follow-up development wells in the Cooper Basin of Australia. The Cooper Basin continues to drive revenues for the Company. Cuisinier 2 and 3 began producing at the end of August 2011 and contributed to Bengal's overall 33% increase in production over fiscal 2011. Bengal achieved a netback of $49.89 per barrel of oil equivalent (boe) in Q3 2012, our highest quarterly netback to date. We achieved our highest average netback overall for the fiscal year ended March 31, 2012 with an average netback of $45.72/boe, an increase of 114% over the year ended March 31, 2011. Australian netbacks for the year ended March 31, 2012 were $68.81 compared to $48.02 in the prior year.

We were privileged to make key appointments to our executive management team in the Calgary office and to add three independent directors to our board this year, greatly expanding our resources and knowledge base. We were pleased to welcome Garret Wilson, Richard Edgar and Gordon MacMahon to our executive management team in August of 2011. Additionally, in January of 2012, we welcomed Stephen N. Inbusch, Bill Wheeler and Dr. Brian J. Moss to the Company's board. These new members of Bengal's board bring a wealth of international exploration, development, regulatory and financial experience.

In April 2012, we announced the purchase of an Ideco H-44 drilling rig for use inititally in the upcoming exploratory drilling program on Bengal's 100% working interest ATP 732P Tookoonooka permit in the Cooper/Eromanga Basin of Queensland, Australia. This drilling program is expected to commence in mid July. The purchase of the rig offers Bengal significant advantages, including, but not limited to, reduced drilling cost structure, reduced program execution risk, tailored drilling programs with room to explore, and control over program development. In addition, ownership of the rig allows Bengal to have the rig available, when not in use by the Company, for future business development opportunities.

Bengal offers a portfolio of low-risk development drilling combined with moderate risk, yet high-impact exploration drilling opportunities. Operations in 2011 and early 2012 set the stage to embark on the largest drilling campaign in the Company's history. This 2012 campaign is expected to include four Cuisinier wells and three Tookoonooka wells. At Cuisinier, the Company continues to enjoy a 100% drilling success rate with the first two wells of the 2012 campaign cased as a future oil producers with net pay ranging from 2.0 to 9.1 metres. These wells establish a platform for further future development and revenue generation from the Barta Block. At Tookoonooka (ATP 732) the company has assembled a portfolio of multi-zone exploration prospects with 3 drilling locations selected for the initial 2012 drilling program.

In addition to Bengal's focus on the Cooper Basin, the Company is also exploring two blocks in India's Cauvery Basin.Despite being in the early stages of exploration, drilling success by other operators in offsetting blocks show significant upside potential for the Company in India.

Bengal has a 30% working interest in 946 square kilometres (233,000 acres) onshore at CY-ONN-2005/1 and a 100% interest in 1,362 square kilometres (340,000 acres) offshore at CY-OSN-2009/1.

Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, commenced a 3D seismic program of approximately 600 square kilometres in late fiscal 2012 which is anticipated to be completed in late calendar 2012. A recent gas discovery was made to the immediate west of the block at Vaderatu. The details of this discovery have not been released but could represent significant upside potential in this block.

CY-OSN-2009/1, located offshore in India's Cauvery Basin is 100% owned and operated by Bengal. The Company is currently evaluating previously recorded 2D and 3D surveys of the block and reprocessing certain seismic records. The block is ideally located and recent competitor activity in the area includes a $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance Industries Limited.

(approximately 270,000 square kilometres) and recent exploration discoveries by Cairn India provided encouragement for the acceleration of Bengal's activity on the block.

The past year was an operational success for Bengal and set the stage for a very active program for the balance of 2012 and 2013. We entered the year with $27.0 million in cash, no debt and a balanced portfolio of exploration and appraisal drilling opportunities. We have improved our ability to execute our own drilling plans through the acquisition of a drilling rig and expect it may provide other growth opportunities in the Cooper Basin in future years.

Bengal offers world class assets managed by a seasoned team of international exploration professionals. Our strong balance sheet and our strategy of low-risk development drilling and high-impact exploration demonstrate our commitment to growing shareholder value over the long-term. We look forward to growing with our employees, our joint venture partners and our shareholders over the coming years.

Sincerely,

Chayan Chakrabarty

Chayan Chakrabarty
President & CEO

MANAGEMENT'S DISCUSSION AND ANALYSIS – JUNE 13, 2012

The following Management's Discussion and Analysis ("MD&A") as provided by the management of Bengal Energy Ltd. ("Bengal" or the "Company") should be read in conjunction with the audited Consolidated Financial Statements and accompanying notes for the years ended March 31, 2012 and 2011. 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.

This is the Company's first annual reporting under International Financial Reporting Standards ("IFRS"). The effective date of the transition to IFRS was April 1, 2010. The transition to IFRS has been reflected by restating previously reported financial statements for 2010. Previously, the Company's financial statements were prepared under Canadian generally accepted accounting principles ("CGAAP"). The adoption of IFRS does not impact the underlying economics of the Company's operations or its cash flows. Note 20 to the consolidated financial statements for the year ended March 31, 2012 contains detailed descriptions of the Company's adoption of IFRS, including reconciliations of the consolidated financial statements previously prepared under CGAAP to those under IFRS.

FISCAL 2012 HIGHLIGHTS

- **New Directors** – On January 12, 2012, Bengal announced the appointment of three independent directors to its board – Dr. Brian J. Moss, Mr. Stephen N. Inbusch and Mr. W.B. (Bill) Wheeler. The new members bring a wealth of international exploration, development and financial experience to the Company as it advances its operations in Australia and India.
- **Production** averaged 135 barrels of oil equivalent per day (boe/d), an increase of 33% over 101 boe/d for the year ended March 31, 2011
- **Revenue** of $4.3 million, an increase of 131% over the year ended March 31, 2011.
- **Netback**(1) of $47.72/boe, an increase of 114% over $21.34/boe for the year ended March 31, 2011; Australian netback of $68.81/boe reflects the strength of the Brent benchmark crude oil prices and is an increase of 43% over $48.02/boe for the previous year.
- **Reserves** – Independent third party year-end reserves evaluation to March 31, 2012 have shown a 9% year-over-year corporate 2P reserves increase, driven by a 32% increase of 2P reserves at Cuisinier, offset by natural declines and 2P reserves reductions of 4% and 21% respectively at Toparoa, Australia and Oak, BC., with the latter being a Canadian natural gas and NGL producing property. Based on 2P reserves additions, the Company replaced over twice its annual production to March 31 2012. Detailed reserves disclosures will be included in Bengal's 2012 Annual Information Form to be filed on SEDAR.
- **Rig Purchase** – On April 5, 2012, the Company announced the purchase of an Ideco H-44 drilling rig and its associated equipment for initial use in its 2012 operated exploratory drilling program in the Cooper Basin. The Rig is a 750 HP carrier-mounted double with a depth capability of 3,000m. The rig provides the Company with an opportunity to reduce the execution risk and cost structure on its upcoming Tookoonooka drilling campaign as well as increase control and flexibility over the program so opportunities can be fully evaluated.
- **Australia Drilling Campaign** – On May 20, 2012, the Company commenced its Australian drilling campaign beginning with three appraisal wells in the Cuisinier field and one step out well Cuisinier North 1, situated 2.9 km north of Cuisinier 1. This non-operated Cuisinier drilling program will be followed by Bengal's 100% operated drilling campaign at Tookoonooka, ATP 732P, which Bengal expects to commence in July 2012.

OPERATING HIGHLIGHTS

$000s except per share, volumes and netback amounts	Three Months Ended 03/31/12	03/31/11	12/31/11	Twelve Months Ended 03/31/12	03/31/11
Revenue					
Natural gas	**$ 59**	$ 125	$ 92	**$ 310**	$ 488
Natural gas liquids	**16**	17	23	**68**	67
Oil	**547**	549	1,213	**3,908**	1,298
Total	**622**	691	1,328	**4,286**	1,853
Royalties	**56**	67	121	**394**	181
% of revenue	**9.0**	9.7	9.1	**9.2**	9.8
Operating & transportation	**312**	295	486	**1,636**	883
Netback(1)	**254**	328	721	**2,256**	788
Cash from (used in) operations:	**486**	(725)	(417)	**(1,142)**	(2,523)
Per share ($) (basic & diluted)	**0.01**	(0.02)	(0.01)	**(0.02)**	(0.10)
Funds used in operations:(2)	**(635)**	(669)	(402)	**(1,459)**	(2,582)
Per share ($) (basic & diluted)	**(0.01)**	(0.02)	(0.01)	**(0.03)**	(0.10)
Net (loss):	**(1,424)**	(890)	(477)	**(7,209)**	(3,340)
Per share ($) (basic & diluted)	**(0.03)**	(0.03)	(0.01)	**(0.14)**	(0.13)
Capital expenditures	**$ 2,233**	$ 1,879	$ 4,327	**$ 10,838**	$ 3,943
Volumes					
Natural gas (mcf/d)	**304**	348	271	**254**	354
Natural gas liquids (boe/d)	**2**	3	4	**3**	3
Oil (bbl/d)	**50**	56	108	**90**	39
Total (boe/d @ 6:1)	**103**	117	157	**135**	101
Netback(1) ($/boe)					
Revenue	**$ 66.62**	$ 65.49	$ 92.03	**$ 86.80**	$ 50.13
Royalties	**6.02**	6.38	8.43	**7.97**	4.90
Operating & transportation	**33.33**	27.97	33.71	**33.12**	23.89
Total	**$ 27.27**	$ 31.13	$ 49.89	**$ 45.72**	$ 21.34

(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 IFRS measure is cash from operations. A reconciliation of the two measures can be found in the table on page 5.

OUTLOOK

The Company entered fiscal 2013 with a strong balance sheet with $27.0 million in cash, no debt and a balanced portfolio of exploration and development drilling opportunities on its extensive land base in Australia and India. The price the Company receives for all of its oil sales in Australia is based on the Dated Brent reference price which has traded at a US $16 premium to WTI for the three months ended March 31, 2012.

AUSTRALIA – Onshore

Authority to Prospect ("ATP") 752 Barta Block

In the Barta Block on ATP 752, where Bengal owns a 25% working interest, the operating company is currently drilling three appraisal wells and one exploration well as a follow up to the four successful exploration and appraisal wells previously drilled. Drilling is expected to be completed by the end of calendar Q2 2012. The appraisal wells are being drilled directly offsetting existing producing wells within the Cuisinier field, targeting the Cretaceous Murta member. Each of these three appraisal well locations is located on 3D seismic in areas where the seismic attributes are consistent with well-developed Murta sands. The step-out exploration well , Cuisinier North – 1, will be drilled some 2.9 kilometers north of the Cuisinier 1 discovery on a satellite structure.This well is located on a 4 - way structural closure and in addition to testing the Murta, the well will also test the Jurassic Birkhead/Hutton formations. These Jurassic formations are the main producing horizons in the Cook oil field situated 5.9 kilometers to the south east of Cuisinier North – 1. The Cook field has produced over 2.5 million barrels to date.

Cuisinier 4, the first appraisal well in the 2012 drilling campaign, is located approximately 600 meters north-west of the Cuisinier 1 discovery well and was cased as a future oil producer. The targeted Murta sand came in high to prognosis with approximately 11.8 meters of DC70 sandstone developed and an estimated minimum 9.1 meters net pay. Wireline logs have confirmed the presence of a minimum 21.8m oil column in oil bearing sands of the Murta member. The entire Murta interval was cored by the operator with a total of 51.2 meters of core cut (49.5 meters recovered). There were hydrocarbon indications through the entire Murta formation, approximately 37 meters in total.

Planning is underway for the shooting of a new 3D seismic survey in early 2013. This seismic is expected to be acquired north of and adjoining the current 3D seismic data set and Cuisinier wells and development area, and will be aimed at imaging Murta, Birkhead and Hutton anomalies, both structural and stratigraphic.

The previously equipped Barta North 1 Murta oil well will be tied into the existing Cuisinier 1 facility via 4.5 kilometers of pipeline. Construction is set to commence in early calendar Q3, with commissioning planned for the end of Q3 2012.

The Operator also plans to tie any successful Murta producers from the 2012 campaign into the existing Cuisinier 1 facility. Engineering work is underway to convert the Cuisinier 1 site to a field satellite where all well production will be produced to and metered. Planning work is also underway to connect the downstream group production from the Cuisinier 1 facility to the neighboring and existing Cook production facility via a new 7.5 km emulsion pipeline. Expected to be operational in early 2013, this new facility configuration and group pipeline will eliminate field and sales oil trucking and is expected to increase run-times and netbacks for the Cuisinier field.

The Cuisinier 1 well has been operating through an Extended Production Test (EPT) as required under the framework of an ATP, and, with the timeframe of the current EPT having expired on December 17, 2011, an extension was applied for on December 9, 2011 by the operating company to the Queensland Regulator, DEEDI (Department of Employment, Economic Development and Innovation). On January 13, 2012, DEEDI advised the Operator that the application to extend the EPT was being reviewed, but asked that the Cuisinier 1 well be shut-in temporarily until the extension was approved or a Cuisinier Production License (PL) granted. The original PL application and accompanying Initial Development Plan were submitted to DEEDI by the Operator in October 2009. Subsequent negotiations followed with DEEDI as to the areal extent of the application area, and as a result, a revised PL was submitted on January 13, 2012. The Cuisinier well remains shut-in and the current net impact to Bengal is 70 bopd. The application for a production license is a routine regulatory requirement which the Company is confident will be approved and the well back on stream in July 2012..

ATP 732 Tookoonooka Block

The acquisition of approximately 422 line kilometers of 2D and 50 square kilometers of 3D seismic data at ATP 732 (Tookoonooka Block) has been completed and the preliminary interpretation is complete. In conjunction with this seismic data acquisition, an evaluation of aeromagnetic and gravity data has also been carried out and has been integrated with the seismic data. This has allowed for the selection of drill locations and the initiation of field work for location evaluation/surveying and also the commencement of the subsequent process of Regulatory and Environmental approvals with the Queensland and Australian Governments. The Company currently plans to commence exploratory drilling with an initial three-well campaign starting in calendar Q3 2012 after the end of the wet season and upon the receipt of all Regulatory and Environmental approvals from the State and Federal Governments. There is also an existing gas pipeline crossing the permit.

The three drill locations selected are targeting Cretaceous and Jurassic oil as well as Permian gas. All three locations have been chosen based on their multi-zone potential with as many as three or four prospective targets on each location. The primary target is oil on two locations and both gas and oil on a third location.

The Cretaceous targets are Wyandra and Murta Formation sandstones. The Jurassic targets are Hutton, Birkhead and Westbourne Formation sandstones. These Cretaceous and Jurassic targets are established producers in existing fields located both southwest and northeast of the Tookoonooka block. Cretaceous reservoirs are deposited in fluvial environments with wells exhibiting porosity ranging from 12% to 33%. Similarly, Jurassic sandstone reservoirs also demonstrate well developed porosities which average around 25% and with very good permeability.

The main Permian aged reservoir of interest is the Toolachee Formation sandstone. These sandstones are multi-zone, fluvial (and overbank) deposits that range from poor to moderate quality reservoirs in the vicinity of ATP 732P. Sands are stacked and interbedded with coals and shales. Porosities in area wells range from 9% to 21%. Good evidence of the Permian gas potential is seen in the Wareena-1 well which tested over 11 MMCFD from the Toolachee sequence. Wareena-1 is located approximately 32 kilometers west of ATP732.

The planning, regulatory and procurement work associated with the drilling, equipping and facility components of the exploration campaign are well underway. Based on the project advancement to date the Company plans to spud the initial exploratory well early in calendar Q3.

The Company is seeking a joint venture partner to participate in the exploration of this permitTo facilitate the Company's drilling plans, Bengal has purchased an Ideco H-44 drilling rig and associated equipment for initial use in the 2012 exploratory drilling program on ATP 732P - the Tookoonooka permit. Operations are currently underway to complete the shipment of the rig and support equipment to Brisbane, Queensland, where along with the final inspections; the maintenance work to bring the rig to a drill-ready stage will be conducted. In parallel with the equipment preparatory work, the process of procuring, training and certifying the drilling crews has also been initiated.

ATP 934 Barrolka Block

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

Australia - Offshore

AC/P 47 Block

The time period in which to complete the seismic work program for the AC/P 47 permit expired on March 2, 2012. At June 13, 2012 the permit has not been relinquished. Bengal has been in communication with the National Offshore Petroleum Tenure Administrator (NOPTA) in regards to the permit tenure and how to proceed with both suspension and extension applications. Concurrently, the company is in conversation with parties interested in a potential joint venture on the block. If an extension is applied for and received, the Company, along with a joint venture partner, would then shoot, process and interpret a minimum of 750 square km of 3D seismic on this permit during 2012 and Q1 2013. The results of this seismic program will give Bengal the option of either committing to drill an exploration well or, if no acceptable prospects are identified from the seismic interpretation, relinquishing the permit. If the permit is relinquished, $0.8 million of historical exploration and evaluation costs plus the Company's share of any seismic program costs will be impaired in the following year.

AC/P 24 Block

Bengal has been advised by the operator of the permit at AC/P 24 that an extension request has been filed for and received for the Kingtree prospect for one year and that initial applications for a retention lease for the Katandra discovery have been made.

Analysis of gas encountered while drilling the Kingtree well indicates the presence of a residual oil column evidencing trap leakage. A northern and separate fault bound closure will be further reviewed for potential future drilling. Bengal has taken an impairment charge against all costs incurred on the block.

India - Onshore

CY-ONN-2005/1 Block

On Bengal's 30% working interest, 233,000 gross acre Block CY-ONN-2005/1 located in onshore Cauvery Basin, Bengal and its joint venture partners, Gas Authority of India Ltd. and Gujarat State Petroleum Corporation, have commenced a 3D seismic program of approximately 600 square km. Weather -related delays in the acquisition program have slowed progress; however, the operator has now completed 55% of this planned seismic data acquisition, with the rest of the program to be completed later in 2012 after the monsoon season subject to weather conditions. As well, airborne magnetometry work was carried out over the permit in association with the seismic program. The seismic and airborne magnetometry work are intended to help the joint venture define drilling locations on the permit. A recent gas discovery was made immediately west of the block at Vadateru; however, details of this discovery have not yet been released.

India - Offshore

CY-OSN-2009/1 Block

Evaluation work is continuing on this 340,000 acre, 100% owned and operated Block CY-OSN-2009/1 in India's offshore Cauvery basin. Activity includes acquiring 2D and 3D surveys previously recorded on the block and in this region and reprocessing of certain available seismic records. Interpretation of the various seismic data sets is nearing completion with several play types and prospects emerging. This has now allowed planning to progress on a new seismic data program. The acquisition of additional seismic data in late 2012 or early 2013 is designed to accelerate the timing of the drilling of an exploration well. Recent competitor activity in the local area, including the $7.2 billion acquisition by BP of a 30% interest in a number of blocks held by Reliance and the recently announced exploration discoveries by Cairn India in nearby Sri Lankan waters provide encouragement for acceleration of the Bengal activity.

SUMMARY

The Company believes it is sufficiently capitalized to undertake its nearer term accelerated exploration plans and fulfill near-term work program commitments for the large acreage position the Company holds. The Company has an attractive and large portfolio of both lower-risk and high-impact drilling opportunities. Development and exploratory drilling planned for the first half of calendar 2012 at Cuisinier on the Barta permit should drive near term and increasingly positive operating income for the Company and set the stage for future development. Potential near-term exploration drilling success on permit ATP 732P, planned for 2012, could create further momentum. Longer term plays in India and in the Timor Sea are designed to potentially add value in 2013 and onward. The Company will continue to evaluate accretive production acquisition, exploration and corporate transaction opportunities, as and where they arise, within and around the Company's core areas.

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

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 abbreviations are used in this MD&A: boe/d means barrels of oil equivalent per day; bbl/d means barrels per day and mcf/d means thousand cubic feet of natural gas per day.

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 do not have any standardized meaning under IFRS and previous GAAP 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 IFRS. 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	**03/31/12**	03/31/11	12/31/11	**3/31/12**	03/31/11
Cash flow from (used in) operations	**486**	(725)	(417)	**(1,142)**	(2,523)
Abandonment expenditures	**3**	–	–	**3**	–
Changes in non-cash working capital	**(1,124)**	56	15	**(320)**	(59)
Funds used in operations	**(635)**	(669)	(402)	**(1,459)**	(2,582)

RESULTS OF OPERATONS

Production

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

Production		Three Months Ended		Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**03/31/12**	03/31/11
Natural gas (mcf/d) [1]	**304**	348	271	**254**	354
NGLs (boe/d) [1]	**2**	3	4	**3**	3
Oil (bbls/d) [2]	**50**	56	108	**90**	39
Total (boe/d)	**103**	117	157	**135**	101

(1) Natural gas and NGL volumes are from the Company's Oak property in Canada
(2) Oil volumes are from the Company's Cooper Basin permits in Australia

For the year ended March 31, 2012, production averaged 135 boe/d, up from 101 boe/d in the prior year. The increase is due to a commencement of production from the Cuisinier 2 and 3 wells in August 2011 partially offset by natural reservoir declines at the Company's Oak British Columbia gas property.

For the three months ended March 31, 2012, production averaged 103 boe/d, down from the 117 boe/d produced in the prior year comparable quarter. The decrease in natural gas production is due to natural declines from the Company's Oak B.C. gas property.

Despite the start up of production from Cuisinier 2 and 3 in August 2011, oil production in the current quarter was 50 b/d compared to 108 b/d in the three months ending December 31, 2011 due to shut-in of the Cuisinier 1 well on January 13, 2012. The well was shut-in at the request of the Department of Employment, Economic Development and Innovation ("DEEDI") while they review the application for a Production License (PL). Production is expected to re-commence in July 2012. The current net impact to Bengal of the shut-in Cuisinier 1 production is 70 b/d.

Pricing

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

Prices and Marketing		Three Months Ended		Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**03/31/12**	03/31/11
Average Benchmark Prices					
AECO 30 day firm ($/mcf)	**$ 2.52**	$ 3.77	$ 3.47	**$ 3.36**	$ 3.50
Dated Brent oil ($US/bbl)	**118.44**	105.32	108.90	**113.84**	87.45
Number of CAD$ for 1 AUD$	**1.06**	0.99	1.04	**1.04**	0.96
Number of CAD$ for 1 USD$	**$ 1.00**	$ 0.99	$ 1.02	**$ 0.99**	$ 1.02
WTI oil ($US/bbl)	**$ 102.76**	$ 94.17	$ 97.43	**$ 97.94**	$ 83.33
Bengal's Realized Price ($CAD)					
Natural gas ($/mcf)	**$ 2.14**	$ 3.96	$ 3.68	**$ 3.33**	$ 3.77
Oil ($/bbl)	**121.06**	109.06	122.62	**119.18**	92.29
NGLs ($/bbl)	**77.37**	60.40	60.45	**63.72**	50.15
Total ($/boe)	**$ 66.62**	$ 65.49	$ 92.03	**$ 86.80**	$ 50.13

Bengal's total realized price on a boe basis increased 73% or $36.67/boe to $86.80 on a year over year basis as a result of higher oil prices and an increased proportion of sales from oil volumes. The increased price is partially offset by a decline in gas prices. Current quarter prices decreased by $25.41 to $66.62 compared to the December 31, 2011 quarter due to further declines in gas prices and a temporary increase in lower priced gas sales volumes relative to total sales volumes while the Cuisinier 1 well is shut in.

Bengal's realized price for its Australian oil production had been based on the Asia Petroleum Price Index (APPI) Tapis Crude benchmark price. Effective January 1, 2011 the price received for Bengal's Australian oil sales is based on Dated Brent quotes as published by Platts Crude Oil Marketwire for the month in which the Bill of Lading occurs plus a Platts Tapis premium. Brent typically has traded at a premium to West Texas Intermediate (WTI) and the Platts Tapis premium averaged US $7.21/bbl over Brent for the three month period ended March 31, 2012.

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

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

Petroleum and Natural Gas Sales

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

Petroleum and Natural Gas Sales ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**03/31/12**	03/31/11
Natural gas[1]	**$ 59**	$ 125	$ 92	**$ 310**	$ 488
NGLs[1]	**16**	17	23	**68**	67
Oil[2]	**547**	549	1,213	**3,908**	1,298
Total	**$ 622**	$ 691	$ 1,328	**$ 4,286**	$ 1,853

(1) Natural gas and NGL sales are from the Company's Oak property in Canada
(2) Oil sales are from the Company's Cooper Basin permits in Australia

Revenue for the 2012 fiscal year was $4,286,000, an increase of 131% or $2,433,000 over the prior fiscal year. The increase in revenue was due to higher oil production ($2,217,000) and oil prices ($396,000) in 2012 as compared to 2011. The increase in oil revenues was partially offset by lower gas revenue due to lower volumes ($123,000) and gas prices ($57,000).

Petroleum and natural gas sales for the fourth quarter of the 2012 fiscal year were $622,000, down from $691,000 in the prior year comparable period due to lower gas volumes and prices partially offset by higher oil prices. The decline in revenue of $706,000 to $622,000 in the current quarter compared to $1,328,000 in the quarter ended December 31, 2011 is mainly due to lower oil volumes resulting from the shut-in of the Cuisinier 1 well.

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

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

Royalties by Type ($000s)	Three Months Ended 03/31/12	03/31/11	12/31/11	Twelve Months Ended 03/31/12	03/31/11
Canada Crown	**$ 2**	$ 12	$ 6	**$ 20**	$ 34
Canada gross overriding	**4**	8	8	**21**	29
Australian Government	**50**	47	107	**353**	118
Total	**$ 56**	$ 67	$ 121	**$ 394**	$ 181
$/boe	**6.02**	6.38	8.51	**7.97**	4.90
% of revenue	**9.0**	9.7	9.1	**9.2**	9.8

Royalties by Commodity	Three Months Ended 03/31/12	03/31/11	12/31/11	Twelve Months Ended 03/31/12	12/31/11
Natural gas					
$000s	**$ 2**	$ 16	$ 10	**$ 26**	$ 49
$/mcf	**0.09**	0.50	0.41	**0.28**	0.38
% of revenue	**4.1**	12.7	11.2	**8.4**	10.1
Oil					
$000s	**$ 50**	$ 47	$ 107	**$ 353**	$ 118
$/bbl	**11.10**	9.43	10.85	**10.75**	8.40
% of revenue	**9.2**	8.6	8.9	**9.0**	9.1
NGLs					
$000s	**$ 4**	$ 4	$ 4	**$ 15**	$ 14
$/bbl	**17.77**	13.92	15.84	**13.65**	10.42
% of revenue	**23.0**	23.1	17.0	**21.4**	20.8

For fiscal 2012, total royalties increased by $213,000 over the prior fiscal year to $394,000 due to higher oil sales volumes and prices partially offset by lower gas volumes and prices. Royalties per boe increased to $7.97/boe from $4.90/boe due to increased oil volumes and prices which attract a higher royalty charge per boe.

Operating & Transportation Expenses

Operating and transportation expenses in the 2012 fiscal year increased by 85% or $753,000 to $1,636,000, compared to $883,000 in the prior year. The increase is due to higher oil volumes from the commencement of production from Cuisinier 2 and 3 in Australia.

In March 2012 the Department of Transport, Energy and Infrastructure for Australia reached a settlement of a longstanding dispute regarding Wharfage costs per barrel with the Buyers group representing the Crude Oil Sale and Purchase Agreement under which Bengal sells its oil. The settlement resulted in an increase from $0.12/bbl to $0.82/bbl for wharfage on all barrels sold since 2002. The impact to Bengal is a charge of $118,000 or $3.60/bbl ($25.93/bbl for the current quarter) on Australian production for the year. This amount is reflected in Australia transportation costs in the table below.

Canadian operating costs increased from $16.53/bbl to $20.27/bbl as fixed costs related to well site personnel and the compressor station are allocated over declining volumes.

Operating costs in Australia for the current quarter are lower due to shut in of the Cuisinier 1 well in January 2012 and lower than forecast road maintenance costs.

Transportation costs in Australia are incurred to transport Bengal's oil production through pipelines from various processing facilities to the centralized Moomba facility which accepts production from 115 gas fields and 39 oil fields through approximately 5,600 km of pipelines. The oil is then sent through a pipeline to Port Bonython, South Australia.

Operating Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**03/31/12**	03/31/11
Australia					
Operating	**$ 37**	$ 119	$ 222	**$ 607**	$ 269
Transportation	**192**	87	177	**693**	236
	229	206	399	**1,300**	505
Canada – Operating costs	**83**	89	87	**336**	378
Total	**$ 312**	$ 295	$ 486	**$ 1,636**	$ 883
Australia					
Operating – ($/boe)	**7.86**	23.70	22.41	**18.47**	19.13
Transportation – ($/boe)	**42.69**	17.21	17.93	**21.15**	16.73
Canada – ($/boe)	**17.18**	16.14	19.24	**20.27**	16.53
Total ($boe)	**$ 33.33**	$ 27.97	$ 33.71	**$ 33.12**	$ 23.89

General and Administration (G&A) Expenses

For the fiscal year 2012, G&A expenses increased $327,000 or 10% to $3,585,000 compared to $3,258,000 in the prior fiscal year. The increase is due to cost of living salary increases, higher professional fees on tax advice on foreign operations and audit fees on changeover to IFRS and higher travel costs as operational activity increases in Australia and India.

In the current quarter, G&A expenses decreased by $162,000 or 15% to $944,000 from $1,104,000 in the prior year comparable quarter. Prior year costs include higher professional fees for resource reports on certain Australian properties.

General and Administrative Expenses ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/12	3/31/11	12/31/11	**03/31/12**	03/31/11
G&A	**$ 944**	$ 1,104	$ 853	**$ 3,585**	$ 3,258

Share-Based Compensation

The Company uses the Black-Scholes pricing model to estimate the fair value of the options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding increase to contributed surplus.

Bengal recognized share-based compensation ("SBC") expense of $1,031,000 before capitalization for fiscal 2012 compared to $531,000 in the prior year. The increase is primarily due to two new hires receiving options in August and September of 2011 and two companywide option grants in fiscal 2012 compared to one in fiscal 2011. The options expire five years from the grant date; they vest one-third on the grant date and one-third on each of the following two annual anniversaries,

Share-Based Compensation ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/12	3/31/11	12/31/11	**03/31/12**	3/31/11
SBC - options	**$ 345**	$ 80	$ 169	**$ 1,031**	$ 463
SBC - warrants	**–**	10	–	**–**	68
	$ 345	$ 90	$ 169	**$ 1,031**	$ 531
SBC – capitalized	**(34)**	–	–	**(34)**	–
Share-based compensation	**$ 311**	$ 90	$ 169	**$ 997**	$ 531

In June 2011, 750,000 stock options were granted to employees, directors and selected consultants 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 was estimated to be $597,000 using the Black-Scholes option pricing model.

In August 2011, 200,000 stock options were granted to a new employee and have an exercise price of $1.05 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options was estimated to be $126,000 using the Black-Scholes option pricing model.

In September 2011, 200,000 stock options were granted to a new employee and have an exercise price of $1.25 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options was estimated to be $148,000 using the Black-Scholes option pricing model.

In March 2012, 1,270,000 stock options were granted to employees, directors and selected consultants and have an exercise price of $1.15 per option which was the market price of the Company's shares at the time of the grant. The fair value of the options was estimated to be $839,000 using the Black-Scholes option pricing model.

In the current year 300,000 options were exercised, 470,667 options expired and 208,335 were forfeited that had not vested.

For the year ended March 31, 2012, Bengal recorded share-based compensation related to outstanding warrants of $nil (2011 - $68,000) and $nil for the three months ended March 31, 2012 (2011 – $nil). At March 31, 2011 the fair value of the warrants had been fully amortized. The warrants expired on August 13, 2011.

Bengal recognized share-based compensation expense before capitalization of $345,000 in the current quarter compared to $90,000 in the comparable prior year's quarter. The increase in expense in the current quarter is primarily due to the grant of 1,270,000 options compared to none in the prior year comparable quarter.

Depletion and Depreciation

Depletion and depreciation increased by $77,000 to $420,000 in the year ended March 31, 2012 from $343,000 in the prior year. The increase in Australia is due to higher production volumes partially offset by a lower depletion rate per barrel. In Canada depletion declined due to lower production volumes at the Company's Oak, B.C. gas property. Depletion per boe declined due to the increases in proved plus probable reserves in Australia as per the March 31, 2012 reserve report prepared by DeGolyer and MacNaughton Canada Limited compared to the prior year.

Depletion per boe increased from $7.35 to $9.93 in the current quarter compared to the prior year comparable quarter. The increase is due to increased depletable costs in Australia from the transfer of the Cuisinier 2, 3 and Barta North 1 well costs from E&E assets to D&P assets without equivalent reserve additions when compared to the Cuisinier 1 discovery well and lower gas reserves due to lower prices.

DD&A Expenses ($000s)	**Three Months Ended**			**Twelve Months Ended**	
	03/31/12	03/31/11	**12/31/11**	**03/31/12**	03/31/11
DD&A – Australia	**$ 51**	$ 34	**$ 91**	**$ 280**	$ 155
DD&A – Canada	**42**	44	**35**	**140**	188
Total	**$ 93**	$ 78	**$ 126**	**$ 420**	$ 343
$/boe – Australia	**11.11**	6.74	**9.18**	**8.51**	11.05
$/boe – Canada	**9.45**	7.90	**7.71**	**8.47**	8.20
$/boe – Total	**$ 9.93**	$ 7.35	**$ 8.72**	**$ 8.50**	$ 9.28

In the year ended March 31, 2012 the Company reported a $4,194,000 (2011 - $nil) impairment loss relating to E&E assets. The impairment mainly relates to costs on offshore Australia permit AC/P 24 which were determined to be impaired after drilling and abandoning the Kingtree well in October 2011 and final drilling costs charged by the operator in the current year for the dry and abandoned Hudson well which was drilled in 2008.

In the current year an impairment loss related to D&P assets of $311,000 (2011 - $nil) was also recognized for the Company's Oak, B.C. gas property. The loss is due to lower forecast gas prices which resulted in the carrying value of the cash generating unit exceeding the fair value less costs to sell of the CGU.

Funds from (used in) Operations and Net Loss

For the year ended March 31, 2012 funds used in operations decreased to ($1,459,000) or ($0.03) per basic and diluted share compared to funds used in operations of ($2,582,000) or ($0.10) per basic and diluted share in the prior period. The improvement in funds flow of $1,138,000 is due to higher oil production from the Cuisinier field in Australia and higher oil prices partially offset by lower gas production and gas 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 (see reconciliation on page 8).

The loss for the year ended March 31, 2012 was $7,209,000 or $0.14 per basic and diluted share compared to a loss of $3,340,000 or $0.13 per basic and diluted share in the prior fiscal year. The increased loss was due to impairment of certain offshore and onshore Australian E&E assets in the amount of $4,194,000 and Canadian D&P assets of $311,000.

CAPITAL EXPENDITURES

Fiscal 2012 capital expenditures of $10,838,000 include $5,664,000 to shoot 400 km of 2D and 50 square km of 3D seismic on onshore Australia permit ATP 732P, $1,527,000 for seismic and geological and geophysical work on the Company's two India permits, $1,173,000 to drill the Kingtree well offshore Australia in the Timor Sea and $702,000 in charges from the operator of the Hudson well which was drilled in 2008. Fiscal 2012 completion costs of $1,580,000 were to complete and equip Cuisinier 2, 3 and Barta North 1 and to tie-in Cuisinier 2 and 3.

Capital Expenditures ($000s)	Three Months Ended			Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**3/31/12**	03/31/11
Land	**$ –**	$ 991	$ –	**$ –**	$ 991
Geological and geophysical	**$ 1,984**	$ 251	$ 4,416	**$ 7,277**	$ 886
Drilling	**62**	736	(251)	**1,876**	1,824
Completions	**82**	–	100	**1,580**	129
Total oil & gas expenditures	**$ 2,128**	$ 1,978	$ 4,265	**$ 10,733**	$ 3,830
Office	**105**	–	–	**105**	–
Total expenditures	**$ 2,233**	$ 1,978	$ 4,265	**$ 10,838**	$ 3,830
Exploration & evaluation expenditures	**2,047**	1,615	4,174	**10,213**	3,338
Development & production expenditures	**186**	363	91	**625**	492
Total net expenditures	**$ 2,233**	$ 1,978	$ 4,265	**$ 10,838**	$ 3,830

Tax Pools

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

Years ended March 31 ($000s)	2012	2011
Canada		
Canadian exploration expense	$ 64	$ 64
Canadian development expense	1,075	1,530
Undepreciated capital cost	435	640
Canadian foreign exploration & development	5,882	2,903
Non-capital losses carry forward	15,655	11,387
Net capital losses	5,878	5,878
Share issue costs	1,147	1,545
Total Canada	30,136	23,947
Australia		
Non-capital losses carry forward	24,590	18,213
Undepreciated capital cost	56	56
Total Australia	24,646	18,269
Total	$ 54,782	$ 42,318

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

At March 31, 2012, the Company had approximately $15.6 million and $24.6 million of non-capital losses in Canada and Australia respectively (2011 - $11.2 million and $18.3 million), available to reduce future taxable income. The Canadian losses expire at various dates from March 31, 2014 to 2032. The Australian non-capital losses have no expiry date.

SHARE CAPITAL

Bengal has an unlimited number of common shares authorized for issuance. On June 13, 2012, there were 52,110,177 common shares issued and outstanding.

In April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,022,000, were $23,478,000.

In June 2011, 750,000 options were granted with an exercise price of $1.32. In August 2011, 200,000 options were granted with an exercise price of $1.05 and in September 2011, 200,000 options were granted with an exercise price of $1.25 per share. In March 2012, 1,270,000 options were granted with an exercise price of $1.15 per share.

In the year ended March 31, 2012, 225,000 options were exercised on a cashless basis resulting in the issuance of 73,828 common shares, 75,000 options were exercised for cash resulting in the issuance of 75,000 shares, 470,667 options expired and 208,335 options were forfeited. There has been no option activity from the year ended March 31, 2012 to the date of this report.

Share-based compensation of $146,000 (2011 - $15,000) has been transferred from contributed surplus to equity as a result of the option exercises.

At June 13, 2012, there were 3,611,665 employee stock options outstanding with an average exercise price of $1.14 per share. Of these, 1,895,002 are exercisable at an average price of $1.08 per share. These options expire between 2012 and 2017 with an average remaining life of 3.5 years.

Trading History	Three Months Ended			Twelve Months Ended	
	03/31/12	03/31/11	12/31/11	**03/31/12**	03/31/11
High	**$ 1.20**	$ 2.33	$ 1.48	**$ 2.06**	$ 2.33
Low	**0.78**	1.22	0.72	**0.72**	0.92
Close	**$ 0.95**	$ 1.95	$ 0.80	**$ 0.95**	$ 1.95
Volume (000s)	**3,742**	14,266	5,070	**19,144**	24,783
Shares outstanding Basic and diluted	**52,110**	37,795	52,110	**52,110**	37,795
Weighted average shares outstanding Basic and diluted	**52,110**	35,532	52,088	**51,488**	25,800

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2012 the Company had working capital of $25.7 million, including cash and short term deposits of $26.9 million and restricted cash of $0.1 million, compared to working capital of $14.1 million, including cash and short term deposits of $14.6 million and restricted cash of $1.2 million at March 31, 2011.

The Company currently has sufficient funds to meet its portion of expenditure obligations as per the approved fiscal 2013 work programs. To finance its future acquisition, exploration, development and operating costs, Bengal may require financing from external sources, including issuance of new shares or executing working interest farmout arrangements. The Company is actively marketing the opportunity for interested parties to farm in to its operated oil and gas permits in India and Australia but there is no assurance these efforts will be successful. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to Bengal.

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	750km^2 3D seismic	March 2, 2012(2)	$7.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$5.5
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$5.3
Onshore Australia – ATP 752	Drill 3 appraisal wells & 1 exploration well	July 31, 2014	$4.9
Onshore Australia – ATP 732	Scouting, cultural heritage & drilling preparation. Drill 3 exploration wells	March 31, 2015	$7.8
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$12.1
Onshore Australia – Ideco H-44 Rig	N/A	Purchase and Sale Agreement signed April 4, 2012	$2.7

(1) Translated at March 31, 2012 exchange rate of US $1.000 = CAD $0.997 and AUD $1.000 = CAD $1.0354

(2) Bengal has applied for an extension to the time period to complete the scheduled work commitment for this offshore permit to the National Offshore Petroleum Titles Administrator (NOPTA) to June 2, 2013. The Company has not relinquished the permit as of the date of these financial statements.

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

Guarantees – India Permits

($000s) CAD	Year Ended March 31, 2012 03/31/12	Year ended March 31, 2011 03/31/11
CY-ONN-2005/1 – Onshore India – year 1	$ –	$ 485
CY-OSN-2005/1 – Onshore India – year 2	1,104	1,077
CY-OSN-2005/1 – Onshore India – year 3	820	–
CY-OSN-2009/1 – Offshore India	151	152
Total Guarantees	**$ 2,075**	**$ 1,714**

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

Other

At March 31, 2012, the contractual obligations for which the Company is responsible for are as follows:

Contractual Obligations ($000s)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 1,263	$ 266	$ 491	$ 506	$ –
Decommissioning obligations	228	–	–	–	228
Total contractual obligations	$ 1,491	$ 266	$ 491	$ 506	$ 228

RELATED PARTY TRANSACTIONS

The Company paid $73,050 in consulting fees to a former 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 including business development, partner meetings and regulatory matters. At March 31, 2012, the Company has an accounts payable balance of $5,089 (March 31, 2011 - $41,328) payable to this former director. At the Company's Annual General Meeting on September 14, 2011, this director did not stand for re-election and has been appointed as Executive Vice President of the Company.

SUBSEQUENT EVENTS

On April 5, 2012 the Company announced the purchase of an Ideco H-44 drilling rig. The purchase price of the Rig is US $1.75 million plus additional costs of approximately US $1.0 million to buy certain ancillary equipment required for drilling operations. At March 31, 2012 CAD 230,000 in costs had been incurred in relation to the Rig.

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

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	**2012**	2011	2010
Total production volumes (boe/d)	**135**	101	134
Natural gas prices ($/mcf)	**3.33**	3.77	4.00
Oil and liquids prices ($/boe)	**117.41**	89.00	67.05
Total production revenue	**4,286**	1,853	1,772
Net loss	**(7,209)**	(3,340)	(4,991)
Per share – basic and diluted	**(0.14)**	(0.13)	(0.27)
Cash from operations	**(1,142)**	(2,523)	(1,650)
Per share – basic and diluted	**(0.02)**	(0.10)	(0.09)
Funds from operations [1]	**(1,459)**	(2,582)	(1,556)
Per share – basic and diluted	**(0.03)**	(0.10)	(0.08)
Total assets	**43,696**	25,829	7,413
Working capital[2]	**25,722**	14,063	1,272

(1) See "Non-GAAP Measurements" on page 7 of this MD&A.
(2) Calculated as current assets minus current liabilities.
(3) The Company has no non-current financial liabilities.

SELECTED QUARTERLY INFORMATION

(000s, except per share amounts	**Quarter Ended**							
	03/31/12	12/31/11	09/30/11	06/30/11	03/31/11	12/31/10	09/30/10	06/30/10
Petroleum and natural gas sales	**$ 622**	$ 1,328	$ 1,017	$ 1,319	$ 691	$ 430	$ 383	$ 349
Cash from (used-in) operations	**486**	(417)	159	(1,371)	(725)	(681)	(455)	(570)
Per share Basic and diluted	**0.01**	(0.01)	0.00	(0.03)	(0.02)	(0.02)	(0.02)	(0.03)
Funds from (used in) operations[1]	**(635)**	(402)	(430)	7	(669)	(808)	(467)	(546)
Per share Basic and diluted	**(0.01)**	0.00	(0.01)	0.00	(0.02)	(0.03)	(0.02)	(0.03)
Net loss	**$ (1,424)**	$ (477)	$ (4,247)	$ (1,061)	$ (890)	$ (1,094)	$ (634)	$ (722)
Per share Basic and diluted	**(0.03)**	(0.01)	(0.08)	(0.02)	(0.03)	(0.04)	(0.04)	(0.04)
Additions to capital assets, net	**$ 2,233**	$ 4,265	$ 2,407	$ 1,933	$ 1,978	$ 1,797	$ 174	$ 93
Working capital	**25,722**	28,798	33,109	35,691	14,063	8,571	11,019	631
Total assets	**43,696**	44,899	45,696	51,072	25,829	17,799	17,538	6,693
Shares outstanding Basic and diluted	**52,110**	52,110	51,961	51,961	37,795	30,262	30,238	18,238
Operations								
Average daily production								
Natural gas (mcf/d)	**304**	271	196	249	348	327	366	381
Oil and NGLs (bbls/d)	**52**	112	97	110	59	39	41	31
Combined (boe/d)	**103**	157	130	152	117	94	102	94
Netback ($/boe)	**$ 27.27**	$ 49.89	$ 51.42	$ 48.92	$ 31.31	$ 22.69	$ 13.33	$ 16.65

(1) See "Non-GAAP Measurements" on page 5 and 6 of this MD&A.

Beginning in the quarter ended June 30, 2010 and continuing through to the quarter ended December 31, 2011, oil volumes were increasing due to commencement of production from the Cuisinier 1 well in the Cooper Basin of Australia in May 2010 and the Cuisinier 2 and 3 wells in the quarter ended September 2011. Oil sales increased in the quarter ended June 30, 2011 due to improvement in truck access to the Cuisinier 1 well which had been restricted due to flooding. Oil sales in the most recent quarter have been impacted from the temporary shut in of Cuisinier 1 on January 13, 2012 while the Company waits for approval of a Production License. Gas volumes declined in the quarter ended September 30, 2011 due to a plant turnaround at the Oak B.C. property and are in a general decline due to natural reservoir declines.

The loss in the quarter ended June 30, 2011 includes an impairment charge of $0.7 million related to exploration and evaluation assets in Australia. The quarter ended September 30, 2011 includes impairment charges of $3.6 million for the AC/P 24 permit which was considered impaired after drilling and abandoning the Kingtree well offshore Australia in the Timor Sea. The current quarter loss includes impairment losses of $367,000 mainly related to the Oak B.C. gas property.

FINANCIAL INSTRUMENTS

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

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

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

Disclosure Controls and Procedures

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

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

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were ineffective at March 31, 2012 due to the material weaknesses noted below.

During the year ended March 31, 2012 the Company put restrictions in place to limit access to all accounting files, spreadsheets and systems to select accounting personnel. This change has eliminated the general control deficiencies over information systems which had been previously disclosed as a material ICFR weakness. While Bengal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

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

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

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, Management and the Board do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with IFRS requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in the MD&A to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 3 of the Consolidated Financial Statements.

Oil and Gas Reserves

Bengal's Proved and Probable oil and gas reserves are 100% evaluated and reported on by independent reserve evaluators to the Reserves Committee comprised of independent directors. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Property and Equipment and Intangible Exploration and Evaluation Assets

Recognition and measurement

The Company accounts for exploration and evaluation ("E&E") costs, in accordance with the requirements of IFRS 6: "Exploration for and Evaluation of Mineral Resources." E&E costs related to each license/prospect are initially capitalized within "intangible exploration and evaluation assets." Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable expenses, including remuneration of production personnel and supervisory management, and the projected costs of retiring the assets (if any), but do not include pre-licensing costs incurred prior to having obtained the legal rights to explore an area, which are expensed directly to earnings as they are incurred.

Exploration and evaluation assets are not depleted. They are carried forward until technical feasibility and commercial viability of extracting a mineral resource is considered to be determined. The technical feasibility and commercial viability is considered to be determined when proved and/or probable reserves are determined to exist or they can be empirically supported with actual production data or conclusive formation tests. A review of each concession agreement is carried out at least annually. Intangible exploration and evaluation assets are transferred to petroleum properties as development and production ("D&P") assets upon determination of technical feasibility and commercial viability.

Petroleum properties and other assets are measured at cost less accumulated depletion, depreciation, and amortization, and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, including qualifying E&E costs on reclassification from intangible exploration and evaluation assets, and for qualifying assets, where applicable, borrowing costs. When significant parts of an item of property and equipment have different useful lives, they are accounted for as separate items.

As at April 1, 2010, the date of transition to IFRS, the cost of petroleum properties and other assets was determined by reference to IFRS 1: "First-time Adoption of International Financial Reporting Standards". The methodology adopted for initial recognition of these costs at transition was the cost model, whereby all non-petroleum assets and all E&E assets were measured at the amount recognized under the Company's previous accounting framework, Canadian GAAP, and assets in the development and production phases were measured at the amount determined for the cost centre to which they relate. The adopted process allocated the development and production asset amounts to the underlying assets pro rata based on proved plus probable reserves as at the date of transition.

Gains and losses on disposal of items of property and equipment are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized in earnings immediately.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as petroleum properties or other assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized property and equipment generally represent costs incurred in developing Proved and/or Probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis.

The carrying amount of any replaced or sold component is derecognized.

Impairment

Estimated future recoverable value of property, plant and equipment and any related impairment charges or recoveries are assessed for impairment when circumstances suggest the carrying amount may exceed its recoverable amount. The recoverable amount calculation requires the use of estimates which are subject to change as new information becomes available. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Depletion, depreciation and amortization

The depletion, depreciation and amortization of petroleum properties and other assets, and any eventual reversal thereof, are recognized in earnings.

The net carrying value of D&P assets included in petroleum properties is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable reserves using estimated future prices and costs. Costs subject to depletion include estimated future development costs necessary to bring those reserves into production. These estimates are reviewed by independent reserve engineers at least annually.

Proved and probable reserves are estimated using independent reserve evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially viable. The specified degree of certainty must be a minimum 90% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and a minimum 50% statistical probability for proved and probable reserves to be considered commercially viable.

Other assets are depreciated at declining balance rates of 20% to 30%.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

Accruals

Estimated accruals for revenues, royalties and operating costs where actual revenues and costs have not been received.

Estimated capital expenditures where actual costs have not been received or for projects that are in progress.

Decommissioning Obligations

The Company is required to set up a provision for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant and equipment and the appropriate liability account over the expected service life of the assets. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of the economic life of the asset, costs associated with abandonment and site restoration, discount rates and review of potential abandonment methods.

Stock-Based Compensation

In order to recognize stock-based compensation costs, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, forfeitures and volatility of the underlying security. These assumptions vary over time.

Production Sharing Agreements

International operations conducted pursuant to PSAs are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the PSAs, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each PSA establishes specific terms for the Company to recover these costs (Cost Recovery Oil) and to share in the production sharing oil. Cost Recovery Oil is determined in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year. Production sharing oil is that portion of production remaining after Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Production sharing oil that is attributable to the government includes an amount in respect of all income taxes payable by the Company under the laws of the respective country.

NEW ACCOUNTING STANDARDS AND PRONOUNCEMENTS

International Financial Reporting Standards ("IFRS")

The adoption of IFRS required the restatement, for comparative purposes, of amounts reported by the Company for the year ended March 31, 2011, including the opening balance sheet as at April 1, 2010. The Company's first annual financial statements prepared under IFRS are the financial statements for the year ended March 31, 2012. These financial statements include reconciliations of the previously disclosed comparative period financial statements prepared in accordance with Canadian GAAP to IFRS, as set out in Note 20.

The following standards and interpretations have not been adopted as they apply to future periods. They may result in changes to the Company's existing accounting policies and other note disclosures:

IFRS 7 (revised) "Financial Instruments: Disclosures"

In October 2010, the International Accounting Standards Board ("IASB") issued amendments to IFRS 7 to provide additional disclosure on the transfer of financial assets including the possible effects of any residual risks that the transferring entity retains. These amendments are effective for annual periods beginning after July 1, 2011; therefore, the Company will adopt them for the year ending March 31, 2013. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements, but the impact, if any, is not expected to be material.

IFRS 9 (revised) "Financial Instruments: Classification and Measurement"

In November 2009, the IASB issued IFRS 9 as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement". In October 2010, the IASB updated IFRS 9 to include the requirements for financial liabilities. IFRS 9 replaces the multiple rules in IAS 39 with a single approach to determine whether a financial asset is measured at amortized cost or fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. IFRS 9 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 10 (new) "Consolidated Financial Statements"

In May 2011, the IASB issued IFRS 10 to replace SIC-12, "Consolidation – Special Purpose Entities", and parts of IAS 27, "Consolidated and Separate Financial Statements". IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 11 (new) "Joint Arrangements"

In May 2011, the IASB issued IFRS 11 to replace IAS 31, "Interests in Joint Ventures", and SIC-13, "Jointly Controlled Entities – Non-monetary Contributions by Venturers". IFRS 11 requires entities to follow the substance rather than legal form of a joint arrangement and removes the choice of accounting method. IFRS 11 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 12 (new) "Disclosure of Interests in Other Entities"

In May 2011, the IASB issued IFRS 12, which aggregates and amends disclosure requirements included within other standards. IFRS 12 requires entities to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 13 (new) "Fair Value Measurement"

In May 2011, the IASB issued IFRS 13 to clarify the definition of fair value and provide guidance on determining fair value. IFRS 13 amends disclosure requirements included within other standards and establishes a single framework for fair value measurement and disclosure. IFRS 13 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IAS 1 (revised) "Presentation of Financial Statements"

In June 2011, the IASB issued amendments to IAS 1 to require separate presentation for items of other comprehensive income that would be reclassified to profit or loss in the future from those that would not. These amendments are effective for annual periods beginning on or after July 1, 2012. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements.

IAS 12 (revised) "Income Taxes"

In December 2010, the IASB issued amendments to IAS 12 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendments introduce a presumption that entities will assess whether the carrying value of an asset will be recovered through the sale of the asset. These amendments are effective for annual periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements, but the impact, if any, is not expected to be material.

IAS 28 (revised) "Investments in Associates and Joint Ventures"

In May 2011, the IASB issued amendments to IAS 28 to prescribe the accounting for investments in associates and set out the requirements for applying the equity method when accounting for investments in associates and joint ventures. These amendments are effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements, but the impact, if any, is not expected to be material.

RISK FACTORS

Companies engaged in the oil and gas industry are exposed to a number of business risks which can be described as operational, financial and political risks, many of which are outside of the Company's control. More specifically, these include risks of economically finding reserves and producing oil and gas in commercial quantities, marketing the production, commodity prices, environmental and safety risks, and risks associated with the foreign jurisdiction in which the Company operates. In order to mitigate these risks, the Company has an experienced base of qualified technical and financial personnel in both Canada and

Australia. Further, the Company has focused its foreign operations and plans to target future foreign operations in known and prospective hydrocarbon basins in jurisdictions that have previously established long-term oil and gas ventures with foreign oil and gas companies.

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

Exploration, Development and Production Risks

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

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

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

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

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

Risks Associated with Foreign Operations

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

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

Substantial Capital Requirements and Liquidity

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

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

Health, Safety and Environment

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

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

Insurance

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

Competition

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

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

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd, Suite 1810, 801 6th Avenue SW., Calgary, Alberta T2P 3W2, by email to info@bengalenergy.ca or by accessing Bengal's website at www.bengalenergy.ca.

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

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

- *Oil and natural gas production levels;*
- *The size of the oil and natural gas reserves;*
- *Projections of market prices and costs;*
- *Expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *Expectations that Bengal's future realized gas and oil prices will coincide with the B.C Station 2 and Brent daily index prices;*
- *Funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cashflows, farm-outs, joint ventures or share issues and funds will be sufficient to meet requirements;*
- *Continuation of exploration and development activities on Block CY-ONN-2005/1 and whether identified play types on this Block will be prospective;*
- *Commencement of exploration and development activities on Block CY-OSN-2009/1;*
- *Continuation of exploration, development activities on Permit AC/P 47 offshore Australia and whether the Company will be granted an extension to the time period to complete the work program on this permit to June 2, 2013 and whether a farm-out partner will be found on acceptable terms to the Company and if not, whether the Company will shoot seismic on this permit;*
- *Obtaining Native Title Agreement on ATP 934P in Australia and commencement of exploration activities;*
- *That drilling activities on ATP 732P will occur;*
- *That drilling of three wells will occur on ATP 752P in calendar Q2 and Q3 of 2012 and seismic activity will follow drilling and that production from Cuisinier 2 and 3 will continue as expected and that a production license will be granted for Cuisinier 1 and it will re-commence production and that Cuisinier 4 will produce oil and that transportation of the oil will occur.*

With respect to the forward looking statements contained in the MD&A, Bengal has made assumptions regarding: future commodity prices; the impact of royalty regimes; the timing and the amount of capital expenditures; production of new and existing wells and the timing of new wells coming on stream; future operating expenses including processing and gathering fees; the performance characteristics of oil and natural gas properties; the size of oil and natural gas reserves; the ability to raise capital; the continued availability of undeveloped land and skilled personnel; the ability to obtain equipment in a timely manner to carry out exploration and development activities; the ability to obtain financing on acceptable terms; the ability to add production and reserves through exploration and development activities; and the continued stability of political, regulatory; tax and fiscal regimes in which the Company has operations.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Management's Discussion and Analysis:

- *Volatility in market prices for oil and natural gas;*
- *Liabilities inherent in oil and natural gas operations;*
- *Uncertainties associated with estimating oil and natural gas reserves;*
- *Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;*
- *Incorrect assessment of the value of acquisitions;*
- *Unable to meet commitments due to inability to raise funds or complete farm-outs;*
- *Geological, technical, drilling and processing problems;*
- *Changes in income tax laws or changes to royalty and environmental regulations relating to the oil and gas industry;*
- *The risk that Bengal may not be successful in raising funds by an equity issue; and*
- *Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.*

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website (www.sedar.com) and at Bengal's website (www.bengalenergy.ca).

These statements speak only as of the date of this MD&A or as of the date specified in the documents incorporated by reference into this Management's Discussion and Analysis, as the case may be.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

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

Management is also responsible for establishing and maintaining appropriate systems of internal control over the company's financial reporting. The internal control system was designed to provide reasonable assurance to management regarding the preparation and presentation of the consolidated financial statements. Management tested and evaluated the effectiveness of its disclosure controls and procedures and internal controls over financial reporting as at March 31, 2012. During this evaluation Management identified weaknesses due to the limited number of finance and accounting personnel at the Corporation dealing with complex and non-routine accounting transactions that may arise and due to a lack of segregation of duties and as a result the controls are not considered effective. All internal control systems, no matter how well designed, have inherent limitations. Therefore, these systems provide reasonable but not absolute assurance that financial information is accurate and complete.

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

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

Chayan Chakrabarty

Chayan Chakrabarty
President & Chief Executive Officer

Bryan Goudie
Chief Financial Officer

June 13, 2012
Calgary, Alberta

AUDITORS' REPORT TO THE SHAREHOLDERS

To the Shareholders of Bengal Energy Ltd.

We have audited the accompanying consolidated financial statements of Bengal Energy Ltd., which comprise the consolidated statements of financial position as at March 31, 2012, March 31, 2011 and April 1, 2010, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years ended March 31, 2012 and March 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditors' responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Bengal Energy Ltd. as at March 31, 2012, March 31, 2011 and April 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended March 31, 2012 and March 31, 2011 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
June 13, 2012
Calgary, Canada

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)

As at	Notes	March 31, 2012	March 31, 2011 Note 20	April 1, 2010 Note 20
ASSETS				
Current assets:				
Cash and cash equivalents	**4**	**$ 26,934**	$ 14,600	$ 1,055
Restricted cash		**135**	1,227	510
Accounts receivable		**1,009**	817	273
Prepaid expenses and deposits		**127**	91	100
		28,205	16,735	1,938
Non-current assets:				
Property, plant and equipment	**18**	**230**	–	–
Petroleum and natural gas properties	**5**	**4,735**	2,030	1,922
Exploration and evaluation assets	**6**	**10,526**	7,064	3,553
		15,491	9,094	5,475
Total assets		**$ 43,696**	$ 25,829	$ 7,413
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities		**$ 2,483**	$ 2,672	$ 666
Non-current liabilities:				
Decommissioning liability	**8**	**228**	159	115
Shareholders' equity:				
Share capital	**9**	**$ 86,246**	$ 62,595	$ 43,460
Warrants	**9**	**–**	705	490
Contributed surplus		**5,779**	4,189	3,890
Accumulated other comprehensive income		**717**	57	–
Deficit		**(51,757)**	(44,548)	(41,208)
		40,985	22,998	6,632
Total liabilities and shareholders' equity		**$ 43,696**	$ 25,829	$ 7,413

Commitments (note 15)

Subsequent event (note 18)

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

Director
Chayan Chakrabarty

Director
James B. Howe

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

(Thousands of Canadian dollars, except per share amounts)

For the years ended March 31,	Notes	2012	2011 (Note 20)
Income			
Petroleum and natural gas revenue		$ 4,286	$ 1,853
Royalties		(394)	(181)
		3,892	1,672
Operating expenses			
General and administrative	**10**	3,585	3,258
Operating and transportation		1,636	883
Depletion and depreciation	**5**	420	343
Impairment	**5,6**	4,505	–
Pre-licensing and E&E expenses		292	82
Share-based compensation		997	531
		11,435	5,097
Operating loss		(7,543)	(3,425)
Other income (expenses)			
Finance income		613	119
Finance expenses	**11**	(68)	(20)
Foreign exchange loss		(211)	(14)
		334	85
Net Loss		(7,209)	(3,340)
Exchange differences on translation of foreign operations		660	57
Total comprehensive loss for the year		$ (6,549)	$ (3,283)
Loss per share	**9**		
- Basic & Diluted		$ (0.14)	$ (0.13)
Weighted average number of shares outstanding (000s)	**9**		
- Basic & Diluted		51,488	25,800

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Thousands of Canadian dollars)

	Share capital	Warrants	Contributed surplus	Accumulated other comprehensive income	Deficit	Total shareholders' equity
Balance at April 1, 2010	$ 43,460	$ 490	$ 3,890	$ -	$ (41,208)	$ 6,632
Net loss for the year	–	–	–	–	(3,340)	(3,340)
Comprehensive income for the year	–	–	–	57	–	57
Issue of share capital (Note 9)	19,135		(17)	–	–	19,118
Share based payments	–	215	316	–		531
Balance at March 31, 2011	**$ 62,595**	**$ 705**	**$ 4,189**	**$ 57**	**$ (44,548)**	**$ 22,998**
Shares outstanding	**37,794,549**					
Balance at April 1, 2011	**$ 62,595**	**$ 705**	**$ 4,189**	**$ 57**	**$ (44,548)**	**$ 22,998**
Net loss for the year	–	–	–	–	(7,209)	(7,209)
Comprehensive income for the year	–	–	–	660	–	660
Issue of share capital (Note 9)	23,651	–	(146)	–	–	23,505
Expiry of warrants	–	(705)	705	–	–	–
Share based payments - expensed	–	–	997	–	–	997
Share based payments - capitalized	–	–	34	–	–	34
Balance at March 31, 2012	**$ 86,246**	**$ –**	**$ 5,779**	**$ 717**	**$ (51,757)**	**$ 40,985**
Shares outstanding	**52,110,177**					

See accompanying notes to the consolidated financial statements.

BENGAL ENERGY LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)

For the periods ended March 31,	Notes	2012	2011
Operating activities			
Net loss for the year		**$ (7,209)**	$ (3,340)
Non-cash items:			
Depletion and depreciation		**420**	343
Impairment		**4,505**	–
Pre-licensing and E&E expenses		**–**	82
Accretion of decommissioning liability		**5**	5
Share-based compensation		**997**	531
Unrealized foreign exchange gain		**(177)**	(203)
Abandonment expenditures		**(3)**	–
Change in non-cash working capital	14	**320**	59
Net cash used in operating activities		**(1,142)**	(2,523)
Investing activities			
Exploration and evaluation expenditures		**(10,213)**	(3,338)
Petroleum and natural gas properties		**(625)**	(492)
Property, plant and equipment		**(230)**	–
Change in restricted cash		**1,092**	(717)
Changes in non-cash working capital	14	**(326)**	1,334
Net cash used in investing activities		**(10,302)**	(3,213)
Financing activities			
Proceeds from issuance of shares, net of issuance costs		**23,505**	19,118
Changes in non-cash working capital	14	**(82)**	77
Net cash from financing activities		**23,423**	19,195
Impact of foreign exchange on cash and cash equivalents		**355**	86
Net increase in cash equivalents		**$ 12,334**	$ 13,545
Cash and cash equivalents, beginning of year		**14,600**	1,055
Cash and cash equivalents, end of year		**$ 26,934**	$ 14,600

See accompanying notes to consolidated financial statements.

BENGAL ENERGY LTD.

Notes to Consolidated Financial Statements (the "financial statements")

Three and twelve months ended March 31, 2012 and 2011
(Tabular amounts are stated in thousands of Canadian 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.

Bengal's registered office is located at 1810, 801 6th Ave SW, Calgary, Alberta.

2. BASIS OF PREPARATION

a) *Statement of compliance*

These consolidated financial statements as at March 31, 2012, 2011, and the opening statement of financial position at April 1, 2010, are the Company's first annual consolidated financial statements to be issued under International Financial Reporting Standards ("IFRS"). As a result, IFRS 1 "First-time Adoption of Internal Financial Reporting Standards" has been applied.

An explanation of how the transition to IFRS has affected the reported consolidated financial position, financial performance and cash flows of the Company is provided in Note 20. That note includes reconciliations as at April 1, 2010, March 31, 2011 and for the year ended March 31, 2011.

The consolidated financial statements were authorized for issuance by the Board of Directors on June 13, 2012.

b) *Basis of measurement*

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

c) *Functional and presentation currency*

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

d) *Use of Estimates and judgments*

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

Critical judgments in applying accounting policies

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

i) Reserves

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

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

ii) Identification of Cash-generating Units

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

iii) Share-based payments

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

Key Sources of uncertainty

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

i) Decommissioning provisions

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

ii) Impairment of petroleum and natural gas assets

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

iv) Income Taxes

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

3. SIGNIFICANT ACCOUNTING POLICIES

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

In addition to the quantitative adjustments from previous GAAP to IFRS, certain comparative amounts have been reclassified to conform to the current years presentation as presented in note 20.

(a) Basis of consolidation:

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

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

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

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

(b) Cash and cash equivalents

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

(c) Provisions

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

Decommissioning and restoration liabilities:

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

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

(d) Oil and natural gas exploration and evaluation expenditures

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

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

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

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

(e) Petroleum and natural gas properties

Carrying value

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

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are

accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depletion and depreciation

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

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

(f) Impairment

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

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

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

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

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

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

Financial assets

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

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

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

All impairment losses are recognized in profit or loss.

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

(g) Financial instruments

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

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

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

(i) Non-derivative financial instruments

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

(ii) Derivative financial instruments

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

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

At March 31, 2012 the Company does not have any derivative financial instruments.

Fair value

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

Share capital

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

(h) Foreign currency translation:

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

(i) Share-based compensation:

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

(j) Revenue recognition:

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

(k) Earnings (loss) per share:

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.

(l) Income taxes:

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

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

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

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

(m) Finance income and expenses

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

(n) Determination of fair value:

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

1) Property, plant and equipment are recognized at fair value in a business combination. The fair value of property, plant and equipment is the estimated amount for which the property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions.

   The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

2) The fair value of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2012 and March 31, 2011 the fair value of these balances approximated their carrying value due to their short term to maturity.

3) The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the

instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behavior), expected dividends, and the risk-free interest rate (based on government bonds).

(o) Future changes to accounting policies:

The IASB has issued the following new standards and amendments, all of which are effective for annual periods beginning on or after January 1, 2013. Although early adoption is permintted, the Company has not done so as of March 31, 2012.

IFRS 7 (revised) "Financial Instruments: Disclosures"

In October 2010, the International Accounting Standards Board ("IASB") issued amendments to IFRS 7 to provide additional disclosure on the transfer of financial assets including the possible effects of any residual risks that the transferring entity retains. These amendments are effective for annual periods beginning after July 1, 2011; therefore, the Company will adopt them for the year ending March 31, 2013. The Company has not transferred any financial assets and there is no impact to its Consolidated Financial Statements.

IFRS 9 (revised) "Financial Instruments: Classification and Measurement"

In November 2009, the IASB issued IFRS 9 as part of its project to replace IAS 39 "Financial Instruments: Recognition and Mearsurement". In October 2010, the IASB updated IFRS 9 to include the requirements for financial liabilities. IFRS 9 replaces the multiple rules in IAS 39 with a single approach to determine whether a financial asset is measured at amortized cost or fair value. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. IFRS 9 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 10 (new) "Consolidated Financial Statements"

In May 2011, the IASB issued IFRS 10 to replace SIC-12, "Consolidation – Special Purpose Entities", and parts of IAS 27, "Consolidated and Separate Financial Statements". IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 11 (new) "Joint Arrangements"

In May 2011, the IASB issued IFRS 11 to replace IAS 31, "Interests in Joint Ventures", and SIC-13, "Jointly Controlled Entities – Non-monetary Contributions by Venturers". IFRS 11 requires entities to follow the substance rather than legal form of a joint arrangement and removes the choice of accounting method. IFRS 11 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 12 (new) "Disclosure of Interests in Other Entities"

In May 2011, the IASB issued IFRS 12, which aggregates and amends disclosure requirements included within other standards. IFRS 12 requires entities to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IFRS 13 (new) "Fair Value Measurement"

In May 2011, the IASB issued IFRS 13 to clarify the definition of fair value and provide guidance on determining fair value. IFRS 13 amends disclosure requirements included within other standards and establishes a single framework for fair value measurement and disclosure. IFRS 13 is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of this standard on its Consolidated Financial Statements.

IAS 1 (revised) "Presentation of Financial Statements"

In June 2011, the IASB issued amendments to IAS 1 to require separate presentation for items of other comprehensive income that would be reclassified to profit or loss in the future from those that would not. These amendments are effective for annual periods beginning on or after July 1, 2012. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements.

IAS 12 (revised) "Income Taxes"

In December 2010, the IASB issued amendments to IAS 12 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendments introduce a presumption that entities will assess whether the carrying value of an asset will be recovered through the sale of the asset. These amendments are effective for annual periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements, but the impact, if any, is not expected to be material.

IAS 28 (revised) "Investments in Associates and Joint Ventures"

In May 2011, the IASB issued amendments to IAS 28 to prescribe the accounting for investments in associates and set out the requirements for applying the equity method when accounting for investments in associates and joint ventures. These amendments are effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the impact of these amendments to its Consolidated Financial Statements, but the impact, if any, is not expected to be material.

4. CASH AND CASH EQUIVALENTS

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

As at ($000s)	March 31, 2012	March 31, 2011
Cash and bank balances	**$ 3,864**	$ 1,880
Short-term deposits	**23,070**	12,720
	$ 26,934	$ 14,600

5. PETROLEUM AND NATURAL GAS PROPERTIES

	Petroleum and Natural Gas Properties	Corporate Assets	Total
	$000s	**$000s**	**$000s**
Cost:			
Balance at April 1, 2010	$ 1,726	$ 196	$ 1,922
Additions	492	-	492
Change in asset retirement obligation	(4)	–	(4)
Exchange adjustments	(46)	-	(46)
Balance at March 31, 2011	2,168	196	2,364
Additions	520	105	625
Capitalized share based compensation	2	–	2
Change in asset retirement obligation	67	–	67
Transfers from E&E assets	2,705	-	2,705
Exchange adjustments	35	-	35
Balance at March 31, 2012	$ 5,497	$ 301	$ 5,798

	Petroleum and Natural Gas Properties	Corporate Assets	Total
	$000s	**$ 000s**	**$000s**
Accumulated depletion, depreciation and impairment losses:			
Balance at April 1, 2010	$ –	$ –	$ –
Depletion and depreciation charge	292	51	343
Exchange adjustments	(9)	-	(9)
Balance at March 31, 2011	283	51	334
Depletion and depreciation charge	383	37	420
Exchange adjustments	(2)	-	(2)
Impairment expense	311	-	311
Balance at March 31, 2012	$ 975	$ 88	$ 1,063
Net carrying value			
At April 1, 2010	$ 1,726	$ 196	$ 1,922
At March 31, 2011	$ 1,885	$ 145	$ 2,030
At March 31, 2012	$ 4,522	$ 213	$ 4,735

During the year the Cuisinier 2 and 3 wells were determined by management to be technically feasible and commercially viable and costs attributed to the wells were transferred from E&E assets to Development and Production (“D&P”) assets within petroleum and natural gas properties.

The depletion expense calculation included $758,000 in Australia and $684,000 in Canada (March 31, 2011 - $1,288,000 and $699,000) for estimated future development costs associated with proved and probable reserves.

In the year ended March 31, 2012 there were indicators of impairment for certain Cash Generating Units (“CGUs”) due to changes in forecasted commodity prices used by the Company’s independent qualified reserves evaluators when compared to March 31, 2011. Accordingly, the Company tested certain CGUs for impairment and determined that the aggregate carrying value of the Canadian gas property at Oak. B.C. was $311,000 higher than the recoverable amount and an impairment was recorded.

The impairment test was based on the net present value of cashflows from oil and gas reserves of the Oak B.C. CGU at a discount rate of 15%. Consideration was also given to acquisition metrics of recent transactions on similar assets.

An impairment test was carried out for the Company's Oak B.C. CGU and was based on the fair value less costs to sell calculations using the following commodity price estimates.

March 31-2012 Table	2013	2014	2015	2016	2017	Percent increase per year to 2023
B.C. Canwest Plantgate - ($Cdn/mcf)	$ 3.00	$ 3.68	$ 4.20	$ 4.59	$ 5.07	~5.0%

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

		Exploration and Evaluation Expenditures
Balance at April 1, 2010	$	3,553
Additions		3,338
Exchange adjustments		173
Balance at March 31, 2011	$	7,064
Additions		10,213
Capitalized share based compensation		29
E&E impairment loss		(4,194)
Transfer to petroleum and natural gas properties		(2,705)
Exchange adjustments		119
Balance at March 31, 2012	**$**	**10,526**

Exploration and evaluation assets consist of the Company's exploration projects in Australia and India which are pending the determination of technical feasibility and commercial viability. Costs primarily consist of acquisition costs, geological & geophysical work, seismic and drilling costs.

	Exploration and Evaluation Assets		
	Australia	India	Total
ATP 732P – Tookoonooka	$ 1,183	$ -	$ 1,183
ATP 752P – Barta Block	1,906	-	1,906
AC/P 24 – offshore	2,021	-	2,021
AC/P 47 – offshore	715	-	715
CY-ONN-2005/1 – onshore	-	490	490
CY-OSN-2009/1 − offshore	-	259	259
Other	490	-	490
March 31, 2011 ($000)	**$ 6,315**	**$ 749**	**$ 7,064**

	Exploration and Evaluation Assets		
	Australia	India	Total
ATP 732P – Tookoonooka	$ 6,847	$ -	$ 6,847
AC/P 47 – offshore	810	-	810
CY-ONN-2005/1 – onshore	-	1,751	1,751
CY-OSN-2009/1 − offshore	-	544	544
Other	574	-	574
March 31, 2012 ($000)	**$ 8,231**	**$ 2,295**	**$ 10,526**

During the year ended March 31, 2012 impairment recognized in profit and loss relates to the following (2011 - $nil):

		Impairments
AC/P 24	$	3,194
Hudson well Australia		702
Wompi Block Australia		298
E&E Impairment charge for year ended March 31, 2012	**$**	**4,194**
D&P Impairment charge for the year ended March 31, 2012		**311**
Impairment charge for the year ended March 31, 2012	**$**	**4,505**

The Kingtree well, located on the AC/P 24 permit off the north coast of Australia in the Timor Sea, was drilled in October of 2011 to evaluate a potential oil target. No commercial hydrocarbons were encountered and the well has been plugged and abandoned. Due to the result of the Kingtree well, an assessment was made of all costs attributable to the AC/P24 permit on which the Kingtree well was drilled. An impairment loss of $3.2 million, equal to all costs associated with the AC/P24 permit, has been recorded in the year ended March 31, 2012.

In addition to the impairment loss on the AC/P24 permit, impairment losses of $0.7 million have been recorded in the year ended March 31, 2012 for final costs of an abandoned well drilled in 2008.

The time period in which to complete the seismic work program on the offshore Australia AC/P 47 permit expired on March 2, 2012. At March 31, 2012, the permit has not been relinquished. The Company has requested an extension to the time period for completing the work progarm from the National Offshore Petroleum Titles Administrator (NOPTA) to June 2, 2013. If the title to the permit is relinquished, $0.8 million of exploration and evaluation assets will be impaired in the following year.

7. 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)		**2012**		**2011**
Loss before taxes	$	7,209	$	3,340
Statutory tax rate		26.13%		27.63%
Expected income tax recovery	$	1,883	$	923
Foreign exchange		74		(307)
Stock-based compensation		(261)		(177)
Effect of change in tax rate & other		(251)		386
Changes in unrecognized tax asset		(1,445)		(825)
	$	–	$	–

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

As of March 31 ($000s)	2012	2011
Non-capital losses	$ 26,978	$ 23,150
Net capital losses	5,878	5,878
P&NG properties	3,566	1,675
Share issue costs	1,147	1,546
Decommissioning obligations	228	97
	$ 37,797	$ 32,346

Income tax rates changed from 27.63 percent in fiscal 2011 to 26.13 percent in fiscal 2012 due to a reduction in federal statutory income tax rates.

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

As of March 31 ($000s)	2012	2011
Property, plant & equipment	$ 3,530	$ 1,372
Foreign exchange	339	572
Non-capital losses	(3,869)	(1,944)
	$ –	$ –

At March 31, 2012, the Company had approximately $15.6 million and $24.6 million of non-capital losses in Canada and Australia respectively (2011 - $11.2 million and $18.3 million), available to reduce future taxable income. The Canadian non-capital losses expire at various dates from March 31, 2013 to 2032. The Australian non-capital losses have no term to expiry.

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At March 31, 2012, the Company has no deferred tax liabilities in respect of these temporary differences.

8. DECOMMISSIONING AND RESTORATION LIABILITY

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

Changes to decommissioning and restoration obligations were as follows:

	March 31, 2012	March 31, 2011
Decommissioning liabilities, beginning of year	**$ 159**	$ 115
Revision	**67**	(4)
Additions	**–**	43
Expenditures	**(3)**	–
Accretion	**5**	5
Decommissioning liabilities, end of year	**$ 228**	$ 159

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total inflation adjusted undiscounted amount of cash flows required to settle its decommissioning and restoration costs at March 31, 2012 is approximately $283,000 (March 31, 2011 – $204,000) which will be incurred between 2019 and 2026. An inflation factor ranging between 2.0% and 3.25% and a risk free discount rate ranging between 2.0% and 3.0% have been applied to the decommissioning liability at March 31, 2012.

9. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares with no par value.

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

(b) Issued:

The following provides a continuity of share capital:

($000s)	Number of Shares		Amount
Balance at April 1, 2010	18,212,783	$	43,460
Issued on cashless exercise of stock options	51,766		–
Issued on exercise of stock options for cash	5,000		2
Transfer from Contributed Surplus	–		17
Shares issued for cash	19,525,000		21,030
Share issue costs	-		(1,914)
At March 31, 2011	37,794,549	$	62,595
Shares issued for cash	14,166,800		25,500
Issued on cashless exercise of stock options	73,828		–
Issued on exercise of stock options for cash	75,000		27
Transfer from Contributed Surplus	–		146
Share issue costs	-		(2,022)
At March 31, 2012	52,110,177	$	86,246

In April 2011, the Company issued 14,166,800 common shares at a price of $1.80 per share. Proceeds of the offering, net of share issue costs of $2,022,000, were $23,478,000.

In October 2011, 75,000 stock options were exercised for $0.36 per share whereby 75,000 common shares were issued for proceeds of $27,000.

In October 2011, 100,000 stock options with an exercise price of $0.36 and 125,000 stock options with an exercise price of $1.26 were exercised based on a cashless exercise whereby 73,778 common shares were issued based on a market share price of $1.28 per share on the date of exercise.

The weighted average share price at the date of exercise in 2012 was $1.28 (2011 - $1.36).

(c) Stock-based compensation - warrants:

The table below provides details of common share purchase warrant activity:

($000s)	Number of Warrants		Amount
Balance April 1, 2010	**940,000**	**$**	**490**
Share-based compensation expense	-		215
Balance March 31, 2011	**940,000**	**$**	**705**
Transfer to contributed surplus on warrant expiry	(940,000)		(705)
Balance March 31, 2012	**-**	**$**	**-**

These warrants expired on August 13, 2011.

(d) Share-based compensation – stock options:

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

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

A summary of stock option activity is presented below:

	Options	Weighted Average Exercise Price
Outstanding at April 1, 2010	**1,802,000**	**$ 1.37**
Granted	660,000	1.41
Expired	(149,667)	2.19
Forfeited	(58,333)	0.75
Exercised	(83,333)	0.45
Outstanding at March 31, 2011	**2,170,667**	**$ 1.38**
Granted	2,420,000	1.20
Forfeited	(208,335)	1.35
Expired	(470,667)	2.68
Exercised	(300,000)	0.74
Outstanding at March 31, 2012	**3,611,665**	**$ 1.14**
Exercisable at March 31, 2012	1,895,002	$ 1.08

	Options Outstanding			Options Exercisable	
Option Price (1)	**Number Outstanding**	**Exercise Price (2)**	**Remaining Life (3)**	**Number Exercisable**	**Exercise Price (2)**
$ 0.36–1.25	2,071,665	$ 1.00	4.3	958,334	$ 0.82
$ 1.26–2.25	1,540,000	$ 1.34	2.5	936,668	$ 1.34
Total	**3,611,665**	**$ 1.14**	**3.5**	**1,895,002**	**$ 1.08**

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

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

For the Year Ended	March 31, 2012	March 31, 2011
Assumptions:		
Risk free interest rate (%)	2% to 4%	2.0%
Expected life (years)	5 yr	5 yr
Expected volatility (%)(1)	68%	72%
Estimated forfeiture rate (%)	6.0%	6.4%
Weighted average fair value of options granted	$0.71	$0.70
Weighted average share price on date of grant	$1.20	$1.41

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

The fair value of stock options granted during the year and quarter ended March 31, 2012 was $1,710,000 (2011 - $450,000).

(e) Loss per share:

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

At March 31, 2012, there were 3,611,665 (March 31, 2011 – 2,170,667) options considered anti-dilutive and at March 31, 2012 there were nil warrants (March 31, 2011 – 940,000) considered anti-dilutive.

10. COMPENSATION OF KEY MANAGEMENT PERSONNEL

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

Year ended March 31 ($000s)		2012		2011
Salaries & employee benefits	$	905	$	913
Stock-based compensation[1]		829		386
General & administrative expenses	$	1,734	$	1,299

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

Salaries and benefits for the year ended March 31, 2012 include a non-recurring retirement payment to former employees of $245,582 (2011 - $230,834).

11. FINANCE EXPENSES

Year ended March 31 ($000s)		2012		2011
Accretion on decommissioning obligations	$	5	$	5
Performance Security Guarantee fee [1]		63		15
Finance expenses	$	68	$	20

(1) Fee paid to Export Development Canada for security guarantee for onshore and offshore India work programs.

12. FINANCIAL RISK MANAGEMENT

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

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

(a) Fair value of financial instruments:

Financial instruments comprise cash and cash equivalents, 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, 2012, Bengal's receivables consisted of $0.6 million (March 31, 2011 - $0.6 million) from joint venture partners and $0.4 million (March 31, 2011 - $0.2 million) of other trade receivables.

Production from the Canadian operations is marketed by the operator. Bengal has not experienced any collection issues with the operator of the property.

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, 2012, the Company had $0.1 million that were considered past due (past due is considered greater than 90 days outstanding). Bengal does not have any reason to believe these receivables will not be collected.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at March 31, 2012 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended March 31, 2012.

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

(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 $2.5 million at March 31, 2012 (March 31, 2011 - $2.7 million). Bengal had $26.9 million in cash (March 31, 2011 - $14.6 million), $0.1 million in restricted cash (March 31, 2011 - $1.2 million) and working capital of $25.7 million at March 31, 2012 (March 31, 2011 - $14.1 million). All accounts payable and accrued liabilities are payable within one year.

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 Risk

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

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

The table below shows the Company's exposure to foreign currencies for its financial instruments:

As at March 31, 2012 ($000s)			
	CAD	**AUD**	**U.S.D**
Cash and short-term deposits	17,423	4,967	4,381
Restricted cash	135	-	-
Accounts receivable	158	231	623
Accounts payable and accrued liabilities	(1,006)	(1,432)	(17)

A 5% strengthening or (weakening) of the CAD as compared to the AUD and USD would have increased or (decreased) profit or loss by $10,000 respectively.

Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the Daily Brent reference price, which trades at a premium to WTI. There were no financial instruments in place to manage commodity prices during the year ended March 31, 2012.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its cash and cash equivalents that have a floating interest rate. The Company is receiving 1.3% interest on its CAD guaranteed investment certificates at a Canadian chartered bank, 4.9% to 5.6% on AUD term deposits in Australia and 0.50% to 1.75% on its USD term deposits at ICICI Canada. A 1.0% decrease in interest rates would have resulted in a $316,000 increase to net loss and cash outflow from operating activities in the year ended March 31, 2012 and a 1.0% increase in interest rates would decrease net loss and cash flow used in operating activities by $316,000 over the same period. The Company had no interest rate derivatives at March 31, 2012.

13. 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. There has been no change in capital management and no externally imposed capital restrictions during the year.

14. CHANGES IN NON-CASH WORKING CAPITAL

Year ended March 31 ($000s)		2012		2011
Accounts receivable	$	137	$	(544)
Prepaid expenses and deposits		(36)		8
Accounts payable and accrued liabilities		(189)		2,006
Total	$	(88)	$	1,470
Relating to:				
Operating	$	320	$	59
Financing		(82)		77
Investing		(326)		1,334
Total	$	(88)	$	1,470

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

The following represents the cash interest received in each period.

Year ended March 31 ($000s)		2012		2011
Cash interest received	$	541	$	11

15. COMMITMENTS AND CONTINGENCIES

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	750km^2 3D seismic	March 2, 2012(2)	$7.2
Onshore India – CY-ONN-2005/1	625km^2 3D seismic + 75km^2 high resolution 3D seismic + 3 wells	March 3, 2014	$5.5
Offshore India – CY-OSN-2009/1	310km 2D seismic & 81km^2 3D seismic	August 15, 2014	$5.3
Onshore Australia – ATP 752	Drill 3 appraisel wells & 1 exploration well	July 31, 2014	$4.9
Onshore Australia – ATP 732	Scouting, cultural heritage & drilling preparation. Drill 3 exploration wells	March 31, 2015	$7.8
Onshore Australia – ATP 934P	Awaiting completion of Native Title before granting of ATP(3)	4 years after grant of ATP	$12.1
Onshore Australia – Ideco H-44 Rig	N/A	Purchase and Sale Agreement signed April 4, 2012	$2.7

(1) Translated at March 31, 2012 exchange rate of US $1.000 = CAD $0.997 and AUD $1.000 = CAD $1.0354

(2) Bengal has applied for an extension to the time period to complete the scheduled work commitment for this offshore permit to the National Offshore Petroleum Titles Administrator (NOPTA) to June 2, 2013. The Company has not relinquished the permit as of the date of these financial statements.

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

At March 31, 2012 the Company had the following lease commitment for office space in Canada and an equipment yard in Darra, Queensland, Australia:

($000s)					
April 2012 to March 2017	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Office lease	$ 1,242	$ 245	$ 491	$ 506	$ –
Darra yard lease	$ 21	$ 21	$ –	$ –	$ –
	$ 1,263	$ 266		$ 506	$ –

Effective April 1, 2012 the Company has entered into a new head lease in Calgary, Canada for a term of five years. Effective May 14, 2012 the Company has entered into a equipment yard lease in Darra, Australia for a term of six months.

16. SUPPLEMENTAL DISCLOSURE

Bengal's consolidated statement of loss and comprehensive loss is prepared primarily by nature of expense. All salaries for the Company are included in general and administrative expenses and for the year ended March 31, 2012 amount to $1,093,000 (2011 - $997,000).

17. RELATED PARTY TRANSACTIONS

During the year ended March 31, 2012 the Company paid $73,050 (2011 - $67,260) in consulting fees to a former 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 including business development, partner meetings and regulatory matters. At March 31, 2012, the Company has an accounts payable balance of $5,089 (March 31, 2011 - $41,328) payable to this former director. At the Company's Annual General Meeting on September 14, 2011, this director did not stand for re-election and has been appointed as Executive Vice President of the Company.

18. SUBSEQUENT EVENT

On April 5, 2012 the Company purchased an Ideco H-44 drilling rig. The purchase price of the Rig is US $1.75 million plus additional costs of approximately US $1.0 million to buy certain ancillary equipment required for drilling operations. At March 31, 2012 CAD $230,000 in costs had been incurred in relation to the Rig.

19. SEGMENTED INFORMATION

As at March 31, 2012, the Company has three reportable operating segments being the Australian, Canadian and India oil and gas operations.

Revenue reported below represents revenue generated from external customers. There were not inter-segment sales in any of the reported periods.

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

For the year ended March 31, 2012 ($000)				
	Australia	**Canada**	**India**	**Total**
Revenue	$ 3,908	$ 378	$ -	$ 4,286
Interest revenue	291	292	30	613
Depletion and depreciation	280	140	–	420
Net loss	(3,277)	(2,994)	(938)	(7,209)
Petroleum and natural gas property expenditures	$ 520	$ 105	$ -	$ 625
Drilling rig expenditures	$ –	$ –	$ 230	$ 230
Exploration and evaluation expenditures	8,667	-	1,546	10,213
Impairment losses	(4,194)	(311)	-	(4,505)
March 31, 2012 ($000)				
Petroleum and natural gas properties				
Cost	4,603	1,195	–	5,798
Impairment loss	–	(311)	–	(311)
Accumulated depletion, depreciation and accretion	(405)	(347)	–	(752)
Net book value	4,198	537	-	4,735
Exploration and evaluation assets	12,425	-	2,295	14,720
Accumulated impairment losses	(4,194)	-	-	(4,194)
Net book value	$ 8,231	$ -	$ 2,295	$ 10,526

For the year ended March 31, 2011 ($000)	Australia	Canada	India	Total
Revenue	$ 1,298	$ 555	$ –	$ 1,853
Interest revenue	70	46	3	119
Depletion and depreciation	155	188	–	343
Net loss	(447)	(2,653)	(240)	(3,340)
Petroleum and natural gas property expenditures	$ 455	$ 37	$ –	$ 492
Exploration and evaluation expenditures	3,109	-	229	3,338
As at March 31, 2011 ($000)				
Petroleum and natural gas properties				
Cost	1,328	1,036	–	2,364
Accumulated depletion, depreciation and accretion	(146)	(188)	–	(334)
Net book value	1,182	848	–	2,030
Exploration and evaluation cost	$ 6,315	$ –	$ 749	$ 7,064

20. TRANSITION TO IFRS

These are the Company's first annual consolidated financial statements prepared in accordance with IFRS. The impact that the transition from Canadian GAAP to IFRS has had on the Company's financial position, financial performance and cash flow is set out in this note.

The significant accounting policies in Note 3 have been applied in the preparaing the consolidated financial statements for the year ended March 31, 2012, the comparative information presented in these consolidated financial statements for the year ended March 31, 2011 and in preparation of the opening IFRS statement of financial position at April 1, 2010 except where certain IFRS 1 exemptions have been applied as described below.

Exemptions Applied

IFRS 1 *First-time Adoption of International Financial Reporting Standards* allows first-time adopters certain exemptions from the general requirement to retrospectively apply IFRS that were effective as at April 1, 2010. The Company has applied the following exemptions:

- IFRS 3 *Business Combinations* has not been applied to acquisitions that occurred before April 1, 2010.
- IFRS 2 *Share-based Payment* has not been applied to equity instruments which vested before the Company's transition date to IFRS.
- The deemed cost of exploration and evaluation assets are the amount determined under Canadian GAAP. For assets in the development or production phases the deemed cost is the amount determined for the cost centre under Canadian GAAP, allocated to the cost centre's underlying assets pro rata using reserve volumes as of April 1, 2010. As a result, the Company measured asset retirement obligations ("ARO") in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* and recognized directly into retained earnings the difference between that amount and the carrying amount of ARO under Canadian GAAP.
- IAS 21 The Company set cumulative translation differences for its foreign operations to zero at transition.
- IFRS 1 also requires that an entity's estimates under IFRS at the date of transition be consistent with estimates made under its Canadian GAAP for the same date, unless there is objective

evidence that those estimates were made in error. The Company's IFRS estimates at April 1, 2010 are consistent with the estimates made under Canadian GAAP for that same date.

Reconciliations from Canadian GAAP to IFRS

An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's consolidated statements of financial position, statements of operations and comprehensive loss for year ended March 31, 2011 is set out in the following reconciliations and in the notes that accompany the reconciliations. Certain amounts on the statements of financial position and the statements of operations and comprehensive loss have been reclassified to conform to the presentation adopted under IFRS.

Reconciliation of Assets, Liabilities and Equity as reported under Canadian GAAP to IFRS

		April 1, 2010		
	Note	**CDN GAAP**	**Adj**	**IFRS**
		($)	($)	($)
ASSETS				
Current assets				
Cash & cash equivalents		1,055	-	1,055
Restricted cash		510	-	510
Accounts receivable		273	-	273
Prepaid expenses & deposits	**A**	103	(3)	100
		1,941	(3)	1,938
Non-current assets				
Petroleum and natural gas properties	**B**	5,427	(3,505)	1,922
Exploration & evaluation assets	**B**	-	3,553	3,553
Total assets		7,368	45	7,413
LIABILITIES & SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable & accrued liabilities		666	-	666
		666	-	666
Non-current liabilities				
Decommissioning liability	**C**	93	22	115
		93	22	115
Shareholders' equity				
Share capital		43,460	-	43,460
Warrants		490	-	490
Contributed surplus	**D**	3,871	19	3,890
Accumulated other comprehensive income		-	-	-
Deficit	**A to D**	(41,212)	4	(41,208)
		6,609	23	6,632
Total liabilities & shareholders' equity		$ 7,368	$ 45	$ 7,413

	Note	March 31, 2011 CDN GAAP	Adj	IFRS
		($)	($)	($)
ASSETS				
Current assets				
Cash & cash equivalents	**A**	14,623	(23)	14,600
Restricted cash	**A**	1,212	15	1,227
Accounts receivable		817	-	817
Prepaid expenses & deposits	**A**	95	(4)	91
		16,747	(12)	16,735
Non-current assets				
Petroleum and natural gas properties	**A & B**	8,777	(6,747)	2,030
Exploration & evaluation assets	**A & B**	-	7,064	7,064
Total assets		25,524	305	25,829
LIABILITIES & SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable & accrued liabilities		2,672	-	2,672
		2,672	-	2,672
Non-current liabilities				
Decommissioning liability	**C**	138	21	159
		138	21	159
Shareholders' equity				
Share capital		62,595	-	62,595
Warrants		705	-	705
Contributed surplus	**D**	4,280	(91)	4,189
Accumulated other comprehensive income	**A**	-	57	57
Deficit	**A to D**	(44,866)	318	(44,548)
		22,714	284	22,998
Total liabilities & shareholders' equity		$ 25,524	$ 305	$ 25,829

Reconciliation of Net Loss for the Year Ended March 31, 2012		CDN GAAP	Adj	IFRS
		$000s	$000s	$000s
Petroleum and natural gas		1,853	-	1,853
Royalties		(181)	-	(181)
Revenue		1,672	-	1,672
Operating expenses				
General and administrative	**1**	3,277	(19)	3,258
Operating and transportation		883	-	883
Depletion and depreciation	**B**	610	(267)	343
Pre-licensing and E&E expense	**B**	-	82	82
Share-based compensation	**D**	641	(110)	531
Total expenses		5,411	(314)	5,097
Operating loss		(3,739)	314	(3,425)
Other income (expenses)				
Finance income		119	-	119
Finance expense	**1,C**	-	(20)	(20)
Foreign exchange gain (loss)		(34)	20	(14)
		85	-	85
Net Loss		(3,654)	314	(3,340)
Exchange differences on translation of foreign operations	**A**	-	57	57
Total comprehensive loss for the year		(3,654)	371	(3,283)

(1) For the year ended March 2011 letter of credit charges of $19,000 have been reclassified as finance expenses.

A. Changes in functional currency

Under IAS 21 - The Effects of Changes in Foreign Exchange Rates, the method of determining functional currency takes into account a broader range of factors than under GAAP. This has resulted in the functional currency of Avery Resources Australia (Pty) Ltd. changing from the Canadian dollar to the Australian dollar and the functional currency of Bengal Energy International Inc. (India) from the Canadian dollar to the U.S. dollar.

As such the value of a number of balance sheet accounts have been revalued with the resulting impact at April 1, 2010 of a decrease in prepaid expenses and deposits of $3,000 and an increase in Development and Production (“D&P”) assets of $48,000, offset by a decrease in deficit of $45,000.

At March 31, 2011, the impact of foreign currency translation resulted in a decrease in cash of $23,000; increase in restricted cash of $15,000; decrease in prepaid expenses and deposits of $4,000; increase in Exploration and Evaluation (“E&E”) assets of $83,000 and an increase in D&P assets of $53,000.

Differences arising from the translation of financial statements that are prepared under a currency other than the presentation currency of the consolidated financial statements are recognized as a separate component of equity. The Company has made use of the exemption in IFRS 1 that such translation differences were deemed zero at the date of transition.

For the year ended March 31, 2011, IFRS transition differences resulted in an exchange gain on translation of foreign operations of $57,000.

B. Exploration and evaluation assets ("E&E") (Note the changes in this section must be added to the changes identified in Note A in order to reconcile to the tables on the prior pages)

IFRS 1 – Deemed Cost. The Company applied the IFRS 1 exemption whereby the value of its opening plant, property and equipment at April 1, 2010 was deemed to be equal to the net book value as determined under Canadian GAAP and the corresponding Cash Generating Units ("CGU's") were tested for impairment. The Company chose to allocate its costs to its CGU's based on proved plus probable reserve volumes.

Under Canadian GAAP the Company followed the full cost method of accounting for oil and gas properties whereby all costs associated with the exploration for and the development of oil and gas reserves were capitalized in country-based cost centers. Under IFRS, pre-exploration costs are recognized in the statement of operations as incurred. Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been determined are capitalized as E&E assets. Once an exploration area has been deemed to be technically feasible and commercially viable, E&E costs are reclassified to development and production assets, a separate category of property and equipment.

The following reclassifications were made from D&P assets under Canadian GAAP:

At April 1, 2010, $3,553,000 was reclassified from D&P to E&E assets offset by a $48,000 foreign exchange gain.

At March 31, 2011, a reduction in D&P assets of $7,091,000 with a corresponding increase in E&E assets of $7,064,000 and $82,000 was charged to the statement of operations relating to pre-licensing costs.

Depletion and depreciation:

Upon transition to IFRS, the Company adopted a policy of depleting and depreciating oil and natural gas interests on a unit of production basis over proved plus probable reserves taking into account the future development costs required to bring those reserves into production. The depletion and depreciation policy under Canadian GAAP was based on unit of production over proved reserves.

There was no impact of this difference on adoption of IFRS at April 1, 2010 as a result of the IFRS 1 exemption taken. For the year ended March 31, 2011 the use of proved plus probable reserves resulted in a decrease to depletion of $267,000 with a corresponding increase to D&P assets.

C. Decommissioning liabilities

Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of the decommissioning, discounted to their net present value upon initial recognition. Under Canadian GAAP, asset retirement obligations were discounted at a credit adjusted risk free rate of seven to ten percent. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted; therefore the provision is discounted at a risk free rate of four percent. Decommissioning obligations are also required to be re-measured based on changes in estimates including discount rates.

The IFRS 1 exemption was utilized for decommissioning obligation associated with oil and gas properties and the Company re-measured asset retirement obligations as at April 1, 2010 under IAS 37 with a corresponding adjustment to opening retained deficit. Upon transition to IFRS this resulted in a $22,000 increase in the decommissioning obligations with a corresponding increase in deficit.

At March 31, 2011, using a risk free rate of four percent the Company increased its decommissioning obligations by $21,000 from the previous GAAP amount offset by an increase to D&P assets of $21,000.

The change in accretion expense under IFRS compared with GAAP was not significant. Under IFRS, accretion of the discount is included in finance expenses whereas under GAAP it is included in depletion and depreciation.

D. Share-based payment transactions

The Company issues certain share-based awards in the form of stock options that vest one-third on the grant date and one-third on each of the next two anniversaries of the grant date. Under IFRS, the fair value of each instalment of the award is considered a separate grant based on the vesting period with the fair value of each instalment determined separately and recognized as compensation expense over the term of its respective vesting period ("graded vesting"). Accordingly, this will result in the amounts of each grant being recognized in income at a faster rate than under GAAP.

Under GAAP, the Company accounts for forfeited stock options in the period in which the forfeiture occurred. Under IFRS, the Company estimated forfeitures at the grant date with revised estimates reflected in each subsequent reporting period. Accordingly, this will result in the amounts of each grant being recognized in income at a slower rate than under GAAP partially offsetting the impact of the graded vesting discussed above.

IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") provides an elective exemption which does not require first-time adopters to apply IFRS 2 Share-based Payment to equity instruments that were granted on or before November 7, 2002, or equity instruments that were granted subsequent to November 7, 2002 and vested before the later of the date of transition to IFRS and January 1, 2005. The Company has used this election.

As a result of this election an increase of $19,000 has been made to contributed surplus with an offsetting increase in the deficit at April 1, 2010.

Share based compensation decreased by $110,000 for the year ended March 31, 2011. An increase of $36,000 in share based compensation expense is offset by a decrease in warrant amortization of $146,000 for the year ended March 31, 2011. These adjustments were offset by a $110,000 decrease to contributed surplus at March 31, 2011.

E. Cash flow statement

The transition from Canadian GAAP to IFRS did not have a material impact on the consolidated statement of cash flows.

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ICICI Bank Ltd. • Calgary, Canada and Mumbai, India

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INVESTOR RELATIONS

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

DISCLOSURE COMMITTEE

All Directors are members of the Committee

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