BENGAL ENERGY LTD.

Amended and Restated

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

MARCH 31, 2011

July 12, 2011

TABLE OF CONTENTS

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	MM	million
STB	standard tank barrels		

Other

AECO	a natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
GCA	gas cost allowance
m	metres
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
$M	thousands of dollars
$MM	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Where any disclosure of reserves data is made in this Annual Information Form that does not reflect all reserves of Bengal, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471
Kilometres Square	Acres	247.105

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta).

"**Bengal**" or the "**Corporation**" means Bengal Energy Ltd.

"**Bengal International**" or "**BEII**" means Bengal Energy International Inc., a wholly-owned subsidiary of Bengal Energy Ltd. incorporated in Alberta on February 12, 2008

"**Bengal Shares**" or "**Common Shares**" means the common shares in the capital of Bengal.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum.

"**DeGolyer**" means DeGolyer and MacNaughton Canada Limited.

"**DeGolyer Report**" means the report of DeGolyer dated May 17, 2011 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at March 31, 2011.

"**Gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Management Committee**" means the committee constituted under the Production Sharing Contract between the Government of India, GAIL India Ltd., Gujarat State Petroleum Corporation Ltd. and Bengal International.

"**Net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities.

"**PSC**" means Production Sharing Contract.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**TSX**" or "**Exchange**" means the Toronto Stock Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being March 31, 2011.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain information regarding Bengal set forth in this document contains forward-looking statements. The use of any of the words "plan", "expect", "project", "intend", "believe", "should", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are typically intended to identify forward-looking statements. Forward-looking statements are not based on historical facts, but rather on Bengal's internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions, not guarantees, and actual events or results may differ materially. In particular, forward-looking statements included in this document include, but are not limited to, statements with respect to: production and performance characteristics of the Corporation's oil and natural gas properties; oil and natural gas production levels and reserve resource estimates; the quantity of oil and natural gas reserves and recovery rates; the extent and results of testing and completion operations with respect to current and future wells; the Corporation's capital expenditure programs; estimated abandonment and reclamation costs and the timing thereof; supply and demand for oil and natural gas and commodity prices; drilling plans and strategy; availability of rigs, equipment and other goods and services; expectations regarding the Corporation's ability to raise capital and continually add to reserves through acquisitions, exploration and development; treatment under government regulatory regimes and tax laws; expected royalties that will be payable; anticipated work programs and land tenure; the granting of formal permits, licences or authorities to prospect or extensions thereof; timing of acquisitions; and realization of the anticipated benefits of acquisitions and dispositions. In addition, statements relating to "reserves" or "resources" are by their nature 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.

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause actual results to vary, including but not limited to risks associated with: the impact of general economic conditions in Canada, Australia, India and globally; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Canada, Australia, India and globally; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities differing from management's expectations; imprecision in reserve and resource estimates; the production and growth potential of Bengal's assets; governmental regulation of the oil and gas industry; obtaining required approvals of regulatory authorities, in Canada, Australia and India; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; failure to settle native title issues where applicable; volatility in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; general risks and liabilities inherent in oil and natural gas operations; risks associated with the marketing and transportation of oil and natural gas; inability to retain drilling rigs and other services necessary to the Corporation's business; incorrect assessment of the value of acquisitions and/or the failure to realize the anticipated benefits of acquisitions; delays resulting from Bengal's inability to obtain required regulatory approvals or other consents, waivers or extensions; and other factors, many of which are beyond the control of the Corporation. Readers are cautioned that the foregoing list of factors is not exhaustive. 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 regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

With respect to forward-looking statements contained in this document, Bengal has made assumptions regarding: the impact of increasing competition; the general stability of the economic and political environment in which Bengal operates; the timely receipt of any required regulatory approvals; the timely settlement of native title issues, where applicable; the timely execution of required contracts and agreements with appropriate government agencies; the ability of Bengal to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Bengal has an interest in to operate the field in a safe, efficient and effective manner; the ability of Bengal to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploitation; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Bengal to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Bengal operates; and the ability of Bengal to successfully market its oil and natural gas products. Although the forward-looking statements contained in this document are based upon assumptions, which management believes to be reasonable, there can be no assurance that actual results will be consistent with these forward-looking statements, as such undue reliance should not be placed on forward-looking statements.

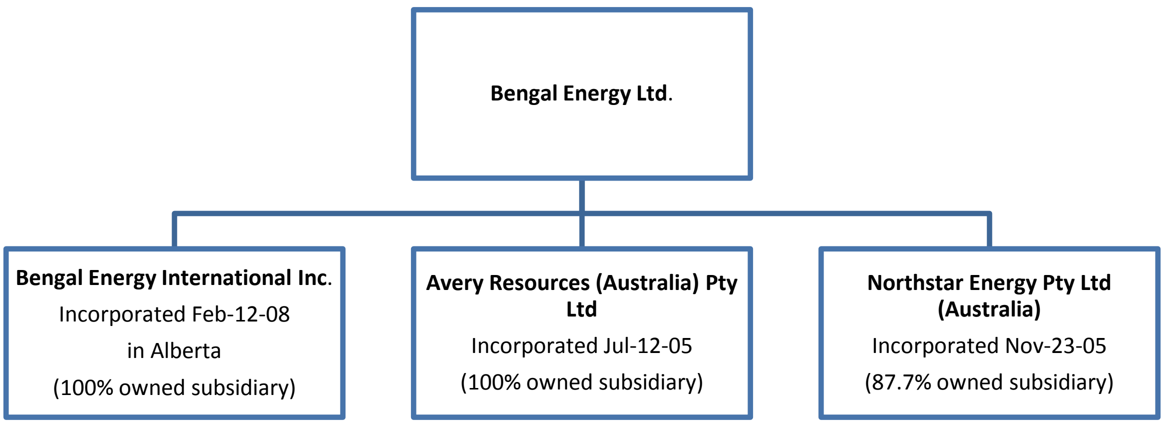
Management has included the above summary of assumptions and risks related to forward-looking statements provided in this document in order to provide shareholders with a more complete perspective on Bengal's current and future operations and such information may not be appropriate for other purposes. Bengal's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Bengal will derive therefrom. These forward-looking statements are made as of the date of this document and Bengal disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

BACKGROUND AND CORPORATE STRUCTURE

The Corporation was incorporated under the ABCA by Articles of Incorporation dated May 13, 1996, as 694460 Alberta Inc. On June 18, 1996, the Corporation filed Articles of Amendment to change the Corporation's name to Briggand Energy Corp., and on October 8, 1996 to amend its share capital and to remove the private company restrictions from its Articles of Incorporation. Following the acquisition of Canop International Resource Ventures Inc. ("**Canop IRV**"), the Corporation changed its name to Canop Worldwide Corp. on March 11, 1997. Canop Worldwide Corp. and Canop IRV were subsequently amalgamated on April 1, 1999. On September 25, 2002 the Corporation's name was changed to Avery Resources Inc. and its outstanding shares were consolidated on a ten-for-one basis. On July 17, 2008 the Corporation's name was changed to Bengal Energy Ltd. and the shares were consolidated on a five-for-one basis.

The Corporation has its registered office at 1400, 350 – 7th Avenue SW, Calgary, Alberta, T2P 3N9 and its head and principal office at 1000, 736 – 6th Avenue SW, Calgary, Alberta, T2P 3T7.

The Bengal Shares trade on the TSX under the symbol "BNG".



DESCRIPTION OF THE BUSINESS AND OPERATIONS

General

Bengal is an international junior oil and gas company based in Calgary, Alberta, Canada and engaged in the business of acquiring international oil and natural gas properties and exploring for, developing and producing oil and natural gas, primarily in India and Australia. The Corporation has an active inventory of oil and gas opportunities in India and Australia and also has natural gas production in British Columbia, Canada and oil production in the Cooper/Eromanga Basin in Australia.

Corporate Strategy

The business objective of Bengal is to grow its production, reserves and resource base on a per-share basis in the international oil and gas industry, primarily in India and Australia. To accomplish this, Bengal will continue to pursue an integrated growth strategy including focused exploration, controlled exploitation, as well as strategic acquisitions within and in proximity of its primary areas of focus of India and Australia. Bengal intends to continue actively to grow its resource and reserves base within its existing acreage, most of which were acquired through bid rounds in India and Australia. In addition, Bengal intends to continue to pursue its growth strategy by building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus.

Bengal plans to pursue a balance between exploration, exploitation and development drilling. Management of the Corporation will consider asset and corporate acquisition opportunities that meet Bengal's business parameters. While Bengal believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration and development of oil and gas has a number of inherent risks. See "*Risk Factors*" herein.

In reviewing potential drilling or acquisition opportunities, Bengal considers the following criteria:

(a) risk capital to secure or evaluate the opportunity;

(b) risked return versus cost of capital;

(c) the performance characteristics of the Corporation's oil and natural gas properties;

(d) oil and natural gas production levels;

(e) the quality of oil and natural gas reserves and recovery rates;

(f) the amount of potential for additional reservoir development;

(g) capital expenditure programs;

(h) supply and demand for oil and natural gas and commodity prices;

(i) drilling plans;

(j) availability of rigs, equipment and other goods and services;

(k) whether sufficient infrastructure exists to provide for planned activity;

(l) expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;

(m) treatment under governmental regulatory regimes and tax laws; and

(n) realization of the anticipated benefits of acquisitions and dispositions.

In addition to the above criteria, in circumstances where Bengal seeks to acquire significant assets with proven reserves, prior to the investment decision being finalized. Bengal will look to obtaining an independent engineering report (whether from the vendor of such assets or otherwise) relating to such reserves.

Bengal may approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life, immediacy of production additions, asset quality and acquisition costs.

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary of the business operations of the Corporation for the periods shown.

Fiscal Year Ending March 31, 2009

Corporate Name Change and Five for One Share Consolidation

On July 17, 2008, at its Annual and Special Meeting of Shareholders, the Corporation received requisite approval for the name change of the Corporation to "Bengal Energy Ltd." and to consolidate its shares on a five for one basis. The name change better reflects the Corporation's broadened international oil and gas focus. On July 22, 2008, the Corporation commenced trading on the TSX under the new trading symbol "BNG".

Award of CY-ONN-2005/1 Block, Cauvery Basin, Onshore India

Bengal and its joint venture partners signed a Production Sharing Contract ("PSC") with the Government of India ("GOI") for the CY-ONN-2005/1 block ("CY-ONN-2005/1") on December 22, 2008. CY-ONN-2005/1 is a block of land measuring approximately 234,000 gross acres located in the Cauvery Basin in the State of Tamil Nadu, India. Pursuant to a joint operating agreement, Bengal has a 30% working interest, GAIL (India) Limited ("GAIL"), the operator, holds a 40% interest and Gujarat State Petroleum Corporation ("GPSC") holds the remaining 30% interest in CY-ONN-2005/1.

Award of Exploration Permit-AC/P47, Timor Sea, Offshore Australia

On March 3, 2009, Bengal was awarded a 100% working interest in exploration permit AC/P47 ("**AC/P47**") with respect to an offshore block of land measuring approximately 864,000 acres located in the Ashmore Cartier area of the Timor Sea. AC/P47 is located in a range of water depths varying between 50 to 900 metres depth with most of the blocks being located in less than 400 metres of water. Bengal is the operator of AC/P47.

Fiscal Year Ending March 31, 2010

Disposition of Kaybob Assets

On September 25, 2009, the Corporation disposed of non-operated production assets (the "**Kaybob Assets**") located in the Kaybob region of Alberta, Canada for aggregate gross proceeds of $2.1 million. The Kaybob Assets contributed approximately $58,000 to the Corporation's net operating income and 29 BOE/d of production for the fiscal year ended March 31, 2010. In aggregate the Kaybob Assets consisted of less than a net section of land and had been determined by management of the Corporation to be non-strategic assets.

Provisional Award of CY-OSN-2009/1 Block, Cauvery Basin, Offshore India

On October 21, 2009, the Corporation, through its wholly owned subsidiary BEII, was provisionally awarded a 100% working interest in the CY-OSN-2009/1 block ("**CY-OSN-2009/1 Block**") by the GOI. CY-OSN-2009/1 Block is a block of land measuring approximately 340,000 acres located in the shallow offshore area of the Southern Cauvery Basin in the State of Tamil Nadu, India.

Acquisition of ATP 732P Cooper/Eromanga Basin, Queensland, Australia

On December 11, 2009, the Corporation entered into an agreement to acquire, from its joint venture partner (the "**JV Partner**"), a 100% working interest in a an exploration block of land in Australia's Cooper/Eromanga Basin in the State of Queensland, Australia (the "**ATP 732P**"). ATP 732P measures approximately 654,000 acres. Prior to entering into this agreement the Corporation had a farm-in agreement to earn a 35% working interest in ATP 732P and following the acquisition the Corporation will hold the entire 100% working interest. The acquisition is subject to the grant of an Authority to Prospect ("**ATP**") to the Corporation from the State of Queensland, Australia. Prior to entering into the acquisition agreement the JV Partner entered into a native title agreement with the Boonthamurra people, which native title agreement is required in order to obtain authorization from the State government to commence exploration activities in the Cooper Basin Block. Bengal expects the acquisition to close and the formal grant of the ATP 732P prior to the end of 2010.

Grant of Petroleum Exploration License CY-ONN-2005/1 Block, Cauvery Basin, Onshore India

On March 3, 2010, Bengal was granted a formal petroleum exploration license for CY-ONN-2005/1.

Fiscal Year Ending March 31, 2011

CY-OSN-2009/1 Block, Cauvery Basin, Offshore India

On June 30, 2010, the Corporation, through its wholly-owned subsidiary BEII, received the formal award from the GOI for the CY-OSN-2009/1 Block and entered into a production sharing contract ("**PSC**") with the GOI. The PSC sets out the terms and conditions for the exploration and development of the CY-OSN-2009/1 Block.

ATP 752P, Cooper/Eromanga Basin, Onshore Australia

Production commenced in May 2010 from the Cuisinier-oil discovery located on ATP 752P in Australia's onshore Cooper/Eromanga Basin. The Cuisinier 1 well (the "**Cuisinier 1 Well**"), which was drilled under a staged farm-in agreement (the "**ATP 752P Farm-in Agreement**") between the Corporation and all of its partners respecting ATP 752P, produced at an initial rate of approximately 340 BOE/d (14.26% net to Bengal) and is located on the approximately 360,033 acre Barta sub-block (the "**Barta Sub-Block**") of ATP 752P and within the 24,958 acre Production License on the Cuisinier block **(**"**PL 303**") which is under application. The Barta Sub-Block is one of two sub-blocks that form the land covered by ATP 752P. The other sub-block is the approximately 215,723 acre Wompi sub-block (the "**Wompi Sub-Block**") in which Bengal has a 22.5% working interest.

On November 12, 2010, the Barta North 1 Exploration Well ("**Barta North 1 Well**") was cased to 2,090 metres total depth by the operator of the well as a potential Murta zone oil well and, following the release of the rig on the Barta North 1 Well on November 13, 2010, Bengal increased its working interest in the Barta Sub-Block to 25% from 14.26%.

On November 26, 2010, the Cuisinier 2 appraisal well (the "**Cuisinier 2 Well**") was cased to 2,037 metres total depth by the operator of the well as a potential Murta zone oil well. The Cuisinier 2 Well is located on the Barta Sub-Block within ATP 752P and approximately 450 metres northeast of the Cuisinier 1 oil discovery. All drilling costs for the Cuisinier 2 Well were carried by the operator under the terms of the farm-in agreement relating thereto.

Australia's Cooper Basin experienced heavy rain and local flooding in December 2010 that continued through January 2011. The Cuisinier 1 Well was temporarily shut in due to road closures resulting from the flooding, which closures prevented the transportation of the Corporation's crude oil production to processing facilities. Prior to being shut-in, the Cuisinier 1 Well was producing approximately 460 barrels of oil per day (115 barrels of oil per day net to Bengal, calculated on a daily producing basis, being the average production rate for 12 producing days out of 30 days in November, 2010). Production on the Cuisinier 1 Well recommenced on January 26, 2011.

The second appraisal well on the Barta Sub-Block (the "**Cuisinier 3 Well** ") located 750 metres south of the Cuisinier 1 Well was cased to 2,040 m total depth by the operator of the well as another potential Murta Zone oil well on March 8, 2011. The Corporation holds a 25 % working interest in the Barta Sub-Block.

ATP 732P, Cooper/Eromanga Basin, Onshore Australia

On March 13, 2011, Bengal completed the acquisition of a 100% working interest in ATP 732P pursuant to a purchase and sale agreement dated December 10, 2009. In connection with the completion of the acquisition the Department of Natural Resources and Mines of the State of Queensland, Australia made the formal grant of ATP 732P. Also in March 2011, Ryder Scott Canada prepared the Ryder Scott Resource Report (as defined herein). See "S*tatement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties – Cooper/Eromanga Basin, Onshore, Australia – ATP732P, Queensland, Australia*" for information regarding the Ryder Scott Resource Report.

General

In August 2010, Messrs. Robert Steele and Richard A.N. Bonnycastle were appointed to the board of directors of the Corporation. Mr. Steele is a professional engineer with over 35 years of experience in the oil and gas industry. Mr.

Bonnycastle is the Chairman of Cavendish Investing, a private investment company with investments in both public and private oil and gas companies.

In September, 2010, Bengal closed a short form prospectus offering of 12,000,000 common shares at a purchase price of $1.00 per common share. The offering was conducted through a syndicate of agents, led by Wellington West Capital Markets Inc. and including Macquarie Capital Markets Canada Ltd., PI Financial Corp. and Toll Cross Securities Inc.

In October, 2010, Bradley Johnson resigned as the Chief Executive Officer and as a director of the Corporation to pursue other opportunities. Following Mr. Johnson's resignation, Chayan Chakrabarty was promoted to President and Chief Executive Officer. Mr. Chakrabarty was formerly the President of the Corporation.

In January, 2011, Bengal closed a short form prospectus offering, which was conducted on a bought-deal basis, of 7,525,000 common shares at an issue price of $1.20 per common share, for aggregate gross proceeds of $9,030,000. The offering was conducted through a syndicate of underwriters led by Mackie Research Capital Corporation and including Wellington West Capital Markets Inc. and Toll Cross Securities Inc.

In February, 2011, Mr. Peter Gaffney was appointed to the board of directors of the Corporation. Mr. Gaffney is a chartered engineer and geologist and was a founding partner of Gaffney, Cline and Associates, an international petroleum management and technical advisory firm.

Recent Developments

In April, 2011, Bengal closed a short form prospectus offering, conducted on a bought-deal basis, pursuant to which it issued 14,166,800 common shares at an issue price of $1.80 per common share for aggregate gross proceeds of $25,500,240. The offering was conducted through a syndicate of underwriters led by Wellington West Capital Markets Inc. and including Mackie Research Capital Corporation and Canaccord Genuity Corp.

During May, 2011, the Cuisinier 2, Cuisinier 3 and Barta North 1 Wells were swab tested. Cuisinier 2 encountered three separate pay sands in the Murta sandstone to a depth 28 m below the base of perforations in Cuisinier 1. Swab test results from the lowest Murta pay sand recovered 95 barrels of oil over approximately a six hour period. The two upper Murta zones at Cuisinier 2 including the equivalent zone to the producing pay sand at Cuisinier 1, may require reservoir stimulation before the upper sands can produce oil. A complete analysis of test results from the wells is expected from the operator.

Cuisinier 3 showed apparent log pay in two Murta zone sandstones. Early swab test results of the upper Murta pay sand, the equivalent zone to the producing Murta pay sand at Cuisinier 1, recovered 37 barrels of oil over an approximately five hour swab period with mechanical difficulties preventing a full evaluation. The swab results require further analysis; however, the upper Murta zone is expected to produce clean oil. The lower zone in this well tested non-commercial rates and will remain suspended.

Both Cuisinier 2 and Cuisinier 3 Wells will be placed on pump with oil pipelined to the Cuisinier 1 lease and an expanded tank system. The ultimate productive capability of each well will be established on pump. The results to date from these Cuisinier appraisal wells indicate that at least a 19 m gross oil column exists within the upper Murta oil zone originally found in Cuisinier 1. Additionally, the lower Murta oil pay, as demonstrated by Cuisinier 2, may extend as much as 21 m deeper. Further analysis of the completion results, additional production from the wells and further step out and appraisal drilling are required to determine and more fully understand the extent of the newly discovered Cuisinier oil pool.

The Barta North 1 Well was perforated over six metres in the upper Murta zone, the equivalent zone to the producing Murta pay sand at Cuisinier 1. Swab testing of this zone recovered 58 barrels of oil over approximately nine hours. The well has been completed as a pumping oil well and the operator is reviewing facility connection options, one of which may be a pipeline from the Barta North 1 Well to the Cuisinier 1 tank system. Perforations were also made to a deeper, Birkhead Formation sandstone which recovered oil at low rates. Although the operator deemed the productivity of this Birkhead oil reservoir to be sub-economic at this time, the result indicates that additional oil potential may exist in the northern part of the Barta Sub-block.

Further step out and appraisal drilling is required to fully understand the extent of both of these new oil pool discoveries. A multi-well drilling program and 3D seismic survey north of the Cuisinier oil pool are in the planning stage and will be implemented in order to pursue potential exploration leads and appraisal opportunities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") was prepared as of May 17, 2011. The effective date of the Statement is March 31, 2011 and the preparation date is May 17, 2011.

Disclosure of Reserves Data

The Corporation engaged DeGolyer to provide an evaluation of the Corporation's proved and proved plus probable reserves as at March 31, 2011. The reserves data set forth below (the "**Reserves Data**") is based upon the DeGolyer Report. DeGolyer is an independent reserves evaluator pursuant to NI 51-101 and the COGE Handbook. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The DeGolyer Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. The Reserves Committee of the Board of Directors has reviewed and approved the DeGolyer Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

The Corporation's reserves are located in Canada and Australia.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs, normal allocated overhead and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF MARCH 31, 2011
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
TOTAL										
Proved Developed										
Producing	12	11	-	-	589	526	5	4	115	103
Non-Producing	17	15	-	-	49	47	1	1	26	24
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**29**	**26**	**-**	**-**	**638**	**573**	**6**	**5**	**141**	**127**
Probable	321	286	-	-	700	477	6	4	444	369
Total Proved Plus Probable	**350**	**312**	**-**	**-**	**1,338**	**1,050**	**12**	**9**	**585**	**496**
CANADIAN PROPERTIES										
Proved Developed										
Producing	-	-	-	-	589	526	5	4	103	92
Non-Producing	-	-	-	-	49	47	1	1	9	9
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**-**	**-**	**-**	**-**	**638**	**573**	**6**	**5**	**112**	**101**
Probable	-	-	-	-	700	477	6	4	123	83
Total Proved Plus Probable	**-**	**-**	**-**	**-**	**1,338**	**1,050**	**12**	**9**	**235**	**184**
AUSTRALIAN PROPERTIES										
Proved Developed										
Producing	12	11	-	-	-	-	-	-	12	11
Non-Producing	17	15	-	-	-	-	-	-	17	15
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	**29**	**26**	**-**	**-**	**-**	**-**	**-**	**-**	**29**	**26**
Probable	321	286	-	-	-	-	-	-	321	286
Total Proved plus Probable	**350**	**312**	**-**	**-**	**-**	**-**	**-**	**-**	**350**	**312**

Notes:

(1) Estimates of Reserves of natural gas include associated and non-associated gas.
(2) "Gross Reserves" are Corporation's working interest reserves before the deduction of royalties.
(3) "Net Reserves" are Corporation's working interest reserves after deductions of royalty obligations plus the Corporation's royalty interests.
(4) The numbers in this table may not add exactly due to rounding.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE — BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
TOTAL											
Proved Developed											
Producing	2,365	2,080	1,851	1,665	1,513	2,365	2,080	1,851	1,665	1,513	18.03
Non-Producing	687	633	584	539	498	687	633	584	539	498	24.50
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**3,052**	**2,713**	**2,435**	**2,204**	**2,011**	**3,052**	**2,713**	**2,435**	**2,204**	**2,011**	**19.25**
Probable	17,280	13,338	10,691	8,827	7,455	17,280	13,338	10,691	8,827	7,455	28.93
Total Proved Plus Probable	**20,332**	**16,051**	**13,126**	**11,031**	**9,466**	**20,332**	**16,051**	**13,126**	**11,031**	**9,466**	**26.46**
CANADIAN PROPERTIES											
Proved Developed											
Producing	1,809	1,539	1,325	1,153	1,014	1,809	1,539	1,325	1,153	1,014	14.42
Non-Producing	240	214	190	169	151	240	214	190	169	151	23.09
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**2,049**	**1,753**	**1,515**	**1,322**	**1,165**	**2,049**	**1,753**	**1,515**	**1,322**	**1,165**	**15.13**
Probable	1,306	1,010	783	606	466	1,306	1,010	783	606	466	9.28
Total Proved Plus Probable	**3,355**	**2,763**	**2,298**	**1,928**	**1,631**	**3,355**	**2,763**	**2,298**	**1,928**	**1,631**	**12.46**
AUSTRALIAN PROPERTIES											
Proved Developed											
Producing	556	541	526	512	499	556	541	526	512	499	49.34
Non-Producing	447	419	394	370	347	447	419	394	370	347	26.36
Proved Undeveloped	-	-	-	-	-	-	-	-	-	-	-
Total Proved	**1,003**	**960**	**920**	**882**	**846**	**1,003**	**960**	**920**	**882**	**846**	**35.93**
Probable	15,974	12,328	9,908	8,221	6,989	15,974	12,328	9,908	8,221	6,989	34.62
Total Proved plus Probable	**16,977**	**13,288**	**10,828**	**9,103,**	**7,835**	**16,977**	**13,288**	**10,828**	**9,103**	**7,835**	**34.72**

Notes:

(1) Reference Item 2.1(1) and (2) of Form 51-101F1.
(2) NPV of future net revenue includes all resource income: Sale of oil, gas by-product reserves; Processing of third party reserves; Other income.
(3) Income Taxes includes all resource income, appropriate income tax calculations and prior tax pools.
(4) The unit values are based on net reserve volumes before income tax (BFIT).
(5) The numbers in this table may not add exactly due to rounding.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF MARCH 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOP-MENT COSTS (M$)	WELL ABANDON-MENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	**7,126**	**785**	**2,757**	**375**	**158**	**3,052**	**-**	**3,052**
Total Proved plus Probable	**46,632**	**6,044**	**17,981**	**1,987**	**289**	**20,332**	**-**	**20,332**
Canadian Properties								
Proved	4,114	460	1,459	15	132	2,049	-	2,049
Proved plus Probable	8,897	1,930	2,713	699	201	3,355	-	3,355
Australian Properties								
Proved	3,012	325	1,298	360	26	1,003	-	1,003
Proved plus Probable	37,735	4,114	15,268	1,288	88	16,977	-	16,977

Notes:

(1) BT = Before Taxes and AT = After Taxes.
(2) Reference Item 2.1(3) of Form 51-101F1.
(3) The numbers in this table may not add exactly due to rounding.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF MARCH 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	920	$35.93
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	1,515	$15.13
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	10,828	$34.72
	Heavy Oil (including solution gas and associated by-products)	-	-
	Natural Gas (including associated by-products)	2,298	$12.46

Notes Regarding the Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the DeGolyer Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

3. The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Forecast Costs and Price Assumptions

4. DeGolyer employed the following pricing, exchange rate and inflation rate assumptions in estimating Bengal's reserves data using forecast prices and costs as at March 31, 2011.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (CANADIAN PROPERTIES AS OF MARCH 31, 2011)

	OIL							
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Natural Gas Alberta Spot Gas Price ($Cdn/Mcf)	Pentanes Plus Edmonton ($Cdn/Bbl)	Butanes Price Edmonton ($Cdn/Bbl)	Inflation Rates[1] %/Year	Exchange Rate[2] ($US/$Cdn)
Forecast								
2011 (3 mo Act)	94.41	88.37	63.12	3.79	90.83	63.41	1.5	1.014
2011 (9 mo Est)	94.41	92.57	72.21	3.84	94.42	69.43	0.0	1.014
2012	94.86	96.29	74.15	4.69	98.22	72.22	2.0	0.980
2013	95.72	97.16	73.84	5.38	99.10	72.87	2.0	0.980
2014	97.10	98.56	73.92	6.02	100.53	73.92	2.0	0.980
2015	99.58	101.08	75.81	6.31	103.11	75.81	2.0	0.980
2016	101.58	103.11	77.33	6.44	105.17	77.33	2.0	0.980
2017	103.61	105.17	78.88	6.58	107.27	78.88	2.0	0.980
2018	105.68	107.27	80.45	6.72	109.42	80.45	2.0	0.980
2019	107.79	109.42	82.06	6.87	111.60	82.06	2.0	0.980
2020	109.95	111.60	83.70	7.01	113.84	83.70	2.0	0.980
2021	112.15	113.84	85.38	7.16	116.11	85.38	2.0	0.980
2022	114.39	116.11	87.09	7.31	118.44	87.09	2.0	0.980
2023+	Escalate oil, gas and product prices at 2.0% per year thereafter.							

Notes:

(1) 2011 forecast pricing is for last nine months (April 1 - Dec. 31) of 2011.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

(4) Weighted average historical prices realized by the Corporation for the year ended March 31, 2011, were \$3.77/Mcf for natural gas, \$92.29/Bbl for light crude oil and \$50.15/Bbl for NGLs.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (AUSTRALIAN PROPERTIES AS OF MARCH 31, 2011)

Year	**BRENT (CDN$/bbl)**
Historical	
2008	93.12
2009	54.45
2010	77.73
Forecast	
2011 (3 months actual, Jan.–Mar.)	106.52
2011 (9 months estimate, Apr.-Dec.)	105.87
2012	97.86
2013	93.80
2014	93.69
2015	94.94
2016	96.84
2017	98.77
2018	100.75
2019	102.76
2020	104.82
2021	106.92
2022	109.05
Thereafter escalate price at:	2.0%

Note:
(1) Crude oil pricing has been estimated by DeGolyer as BRENT blend in Canadian dollars.

5. Well abandonment costs for wells with reserves or without reserves assigned have been included. Additional abandonment costs associated with lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. The extent and character of all factual data supplied to DeGolyer were accepted by DeGolyer as represented. No field inspection was conducted.

Reserves Reconciliation

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

(CANADIAN PROPERTIES AS AT MARCH 31, 2011)

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
March 31, 2010	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions[1]	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-
Dispositions[2]	-	-	-	-	-	-
Economic Factors[3]	-	-	-	-	-	-
Production	-	-	-	-	-	-
March 31, 2011	-	-	-	-	-	-

	NATURAL GAS LIQUIDS			NATURAL GAS			TOTAL		
FACTORS	Gross Proved (Bbl)	Gross Probable (Bbl)	Gross Proved Plus Probable (Bbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (BOE)	Gross Probable (BOE)	Gross Proved Plus Probable (BOE)
March 31, 2010	**7,983**	**7,342**	**15,325**	**739**	**679**	**1,418**	**131,150**	**120,509**	**251,658**
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions[1]	(622)	(428)	(1,050	41	63	104	6,211	10,072	16,283
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions[2]	-	-	-	-	-	-	-	-	-
Economic Factors[3]	(138)	(452)	(590)	(13)	(42)	(55)	(2,305)	(7,452)	(9,757)
Production	(1,329)	-	(1,329)	(129)	-	(129)	(22,829)	-	(22,829)
March 31, 2011	**5,894**	**6,462**	**12,356**	**638**	**700**	**1,338**	**112,227**	**123,129**	**235,356**

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes; economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions.

(2) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.

(3) Includes economic revisions related to price and royalty factor changes.

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

(AUSTRALIAN PROPERTIES AS AT MARCH 31, 2011)

FACTORS	LIGHT AND MEDIUM OIL Gross Proved (Bbl)	LIGHT AND MEDIUM OIL Gross Probable (Bbl)	LIGHT AND MEDIUM OIL Gross Proved Plus Probable (Bbl)	HEAVY OIL Gross Proved (Bbl)	HEAVY OIL Gross Probable (Bbl)	HEAVY OIL Gross Proved Plus Probable (Bbl)
March 31, 2010	**51,038**	**48,800**	**99,838**	**-**	**-**	**-**
Extensions	16,791	239,479	256,270	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions(1)	(25,065)	30,099	5,034	-	-	-
Discoveries	-	2,909	2,909	-	-	-
Acquisitions(2)	-	-	-	-	-	-
Dispositions(2)	-	-	-	-	-	-
Economic Factors(3)	-	-	-	-	-	-
Production	(14,065)	-	(14,065)	-	-	-
March 31, 2011	**28,699**	**321,287**	**349.986**	**-**	**-**	**-**

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Bbl)	NATURAL GAS LIQUIDS Gross Probable (Bbl)	NATURAL GAS LIQUIDS Gross Proved Plus Probable (Bbl)	NATURAL GAS Gross Proved (MMcf)	NATURAL GAS Gross Probable (MMcf)	NATURAL GAS Gross Proved Plus Probable (MMcf)	TOTAL Gross Proved (BOE)	TOTAL Gross Probable (BOE)	TOTAL Gross Proved Plus Probable (BOE)
March 31, 2010	**-**	**-**	**-**	**-**	**-**	**-**	**51,038**	**48,800**	**99,838**
Extensions	-	-	-	-	-	-	16,791	239,479	256,270
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions(1)	-	-	-	-	-	-	(25,065)	30,099	5,034
Discoveries	-	-	-	-	-	-	-	2,909	2,909
Acquisitions(2)	-	-	-	-	-	-	-	-	-
Dispositions(2)	-	-	-	-	-	-	-	-	-
Economic Factors(3)	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	(14,065)-	-	(14,065)
March 31, 2011	**-**	**-**	**-**	**-**	**-**	**-**	**28,699**	**321,287**	**349.986**

Notes:

(1) Includes technical revisions due to reservoir performance, geological and engineering changes; economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions.
(2) Includes production attributable to any acquired interests from the acquisition date to effective date of the report and production realized from disposed interests from the opening balance date to the effective date of disposition.
(3) Includes economic revisions related to price and royalty factor changes.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Bengal attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two-year time frame. The Corporation has no attributed proved undeveloped reserves as at March 31, 2011.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of Bengal's three most recent financial years and before that time, in aggregate:

Year	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)	NGLs (Mbbl)	Total (MBOE)
Aggregate Prior to 2009	54.1	325.0	13.2	121.5
2009	6.0	514.0	5.0	96.7
2010	6.1	577.0	6.2	108.5
2011	6.2	584.0	5.4	108.9

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe.

In general, once probable undeveloped reserves are identified they are scheduled into Bengal's development plans.

A number of factors could result in delayed or cancelled development plans. Such factors may include changing economic conditions due to oil and natural gas pricing, operating and capital expenditure fluctuations. Changing technical conditions resulting in production anomalies such as premature water break through or higher than anticipated production declines may result in the delay or cancellation of development plans. In wells that have encountered multiple zones, a prospective zone completion may be delayed until the initial completion is no longer economic. Larger development program may need to be spread out over several years to optimize capital allocation and facility utilization. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans.

The DeGolyer Report indicates the Bengal has 6,200 barrels of light oil, 583 million cubic feet of natural gas and 5,400 barrels of natural gas liquids reserves defined as "probable undeveloped". Of this amount, all of the Probable Undeveloped oil reserves are associated with the Toparoa Property in Australia and are in a forecast offset drilling location in the shallow Cadna-owie formation. These reserves are expected to be developed when the deeper Hutton zone production reaches its economic limit. All of the Probable Undeveloped natural gas and natural gas liquids (NGL's) exist in Canada and are associated with the Oak-Cecil property in North East British Columbia. These reserves are in proposed infill and step out locations offsetting current natural gas producers. These reserves will be developed once natural gas prices return to levels that will support their economic development.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

For additional details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see the Corporation's management's discussion and analysis of financial condition results of operations and cash flows for Fiscal 2011 as well as the " Risk Factors" "Principal Properties" sections here in.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
TOTAL		
2012	360	811
2013	15	941
2014	-	-
2015	-	-
2016	-	-
Thereafter	-	235
Total Undiscounted	**375**	**1,987**
CANADIAN PROPERTIES		
2012	-	-
2013	15	699
2014	-	-
2015	-	-
2016	-	-
Thereafter	-	-
Total Undiscounted	**15**	**699**
AUSTRALIAN PROPERTIES		
2012	360	811
2013	-	242
2014	-	-
2015	-	-
2016	-	-
Thereafter	-	235
Total Undiscounted	**360**	**1,288**

Notes:

(1) Future Development Costs shown are associated with booked reserves in the Reserves Report and do not necessarily represent the Corporation's full exploration and development budget.
(2) The numbers in this table may not add exactly due to rounding.

On an ongoing basis, Bengal will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. Bengal estimates that $375,000 will be sufficient to fund the future development costs of its proved reserves disclosed above and $1,987,000 will be sufficient to fund the future development costs of the proven probable reserves disclosed above. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue or make the development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada, Australia and India.

The following is a description of the Corporation's principal oil and natural gas properties as at March 31, 2011, unless otherwise stated. Production stated is gross production to the Corporation and, unless otherwise stated, is average daily production during the year ended March 31, 2011 based on operator statements. The reserve amounts stated are gross reserves, as at March 31, 2011 based on forecast costs and prices as evaluated in the DeGolyer Report (see "*Reserves Data*"). The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Oak, British Columbia, Canada

The Oak area of British Columbia is located in the Peace River Block in Townships 86 and 87-17W6. The Oak area is characterized by multi-zone, gas-prone reservoirs which include the Halfway, Baldonnel and Dunlevy/Gething formations each of which produce gas for Bengal from the property. The Corporation holds 41.9% working interest in Section 30 86-17W6M from P&NG to base of the Charlie Lake formation and 29.7% from below the base of Charlie Lake to the base of the Artex-Halfway-Doig formation. The Corporation also holds 30% working interest in Section 31 86-17W6M and 50% in Section 20 87-17W6M. As per the Dominion Land Survey, each full section is comprised of 640 acres. Additionally, Bengal has 12.2% interest in a gas compressor and related gas gathering system in the local area which offers some competitive advantage. Bengal has identified additional development and the potential for down-spacing opportunities. The Corporation currently has 2 producing wells. Bengal's net gas production for the year ended March 31, 2011 averaged 59 BOE/d (6:1 conversion) from the Oak property (down from 79 BOE/d from the year ended March 31, 2010).

Ashmore Cartier Area, Timor Sea, Offshore Australia

Permit AC/P47

On March 3, 2009, Bengal was awarded a 100% interest in exploration permit AC/P47. AC/P47 occupies an area of 3,485 km^2 (Bengal net 864,128 acres) in the Ashmore Cartier area of Timor Sea. The water depth averages less than 400 metres. The anticipated target reservoir zones are high quality Triassic reservoir sandstones, as demonstrated to be present by an offsetting well sitting at moderate depths ranging between 1,800 and 2,600 metres. The same Triassic sandstones are productive for oil in the adjoining Vulcan Graben.

Bengal's technical evaluation of the block, based on an existing grid of 2D seismic data, indicated the existence of substantial untested structures, some in excess of 90 km^2 in size, and with potentially as much as 150 metres of possible closure. The existing lone well drilled in 1973 was evidenced to have been drilled largely off-structure and as such constitutes an incomplete and invalid test of the true hydrocarbon potential of the block.

After the award of AC/P47, Bengal management retained DeGolyer, a worldwide petroleum engineering and consulting firm, to prepare an independent assessment (the "**AC/P47 Resource Assessment**") of the resource potential of the principal prospect initially defined by Bengal on AC/P47. DeGolyer determined that the Best Estimate (P50) of the unrisked prospective oil resource attributable to a single prospect initially defined on AC/P47 was 590.4 million barrels of recoverable oil. DeGolyer also estimated the Unrisked Mean prospective resource attributable to the initially assessed prospect was 736.5 million barrels of recoverable oil. DeGolyer's corresponding Geologic Risk-Adjusted Mean Estimate of the prospective resource contained in this initial prospect was 90.2 million barrels of recoverable oil.

The DeGolyer resource estimates were prepared in accordance with the requirements of NI 51-101 and the COGE Handbook. Capitalized terms related to resource classifications are based on the definitions and guidelines in the COGE Handbook. DeGolyer's independent prospective resource estimates, as of March 31, 2009, are shown below:

AC/P47 Gross Prospective Resources (1) (In Thousands of Barrels)

Unrisked				Geologic Risk-Adjusted Mean Estimate (6)
Low Estimate (2)	Best Estimate (3)	High Estimate (4)	Mean Estimate (5)	
206,492	590,444	1,456,734	736,464	90,217

Subject to the following notes:

(1) Gross Prospective Resources are those quantities of petroleum that are estimated, as of March 31, 2009, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. **There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.**

(2) The Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered. This term reflects a P90 confidence level where there is a 90% chance that a successful discovery will be more than this resource estimate.

(3) The Best (Median) Estimate is considered to be the best estimate of the quantity that will actually be recovered. This term reflects a P50 confidence level where the successful discovery will have a 50% chance of being more than this resource estimate.

(4) The High Estimate is considered to be an optimistic estimate of the quantity that will actually be recovered. This term reflects a P10 confidence level where there is a 10% chance that the successful discovery will be more than this resource estimate.

(5) The Mean Estimate is the probability-weighted average, which typically has a probability in the P45 to P15 range, depending on the variance of prospective resources volume or associated value.

(6) The AC/P47 Resource Assessment is available on the Corporation's SEDAR profile at www.sedar.com.

(7) The Geologic Risk-Adjusted Mean Estimate ("Pg-Adjusted Mean Estimate") is the probability-weighted average of the hydrocarbon quantities potentially recoverable if a prospect portfolio were drilled, or if a family of similar prospects were drilled. The Pg-Adjusted Mean Estimate is a "blended" quantity. It is a mean estimation of both volumetric uncertainty and geological risk. It considers and quantifies the geological success and geological failure outcomes. Consequently it represents the average or mean "geologic" outcome of a drilling and exploration program. It is calculated as Pg multiplied by the mean estimate.

Management is aware of significant additional leads and prospects on AC/P47 which it believes, with further acquisition of additional seismic data, can also be assessed and assigned prospective resources by an independent evaluation under COGE guidelines.

AC/P47 has an initial six-year term, divided into two three-year phases. The first year of the work program (commencing on March 3, 2009) was varied under the approval of the government regulator whereby a combination of 2D seismic data was reprocessed and 300 km of new 2D seismic data was acquired. The year one work program has been completed and the permit is currently in the third year. In years two and three, Bengal has committed to acquire and process a minimum of 750 square kilometres of new 3D seismic. Bengal has sought approval for the variation and timing of its mandated work program for the second and third year of the work program. A formal response from the regulators and the approval of the variations in the work program are anticipated in mid-calendar 2011. The expiry of the first phase presently remains as March 3, 2012. Subject to these regulatory approvals, and as to whether a partnership or farm-out can be arranged the Corporation will endeavour to see that the new 3D seismic survey will be acquired on AC/P47 in late 2011 or early 2012. The government approval of the applied-for adjustments to the work-program is necessary if the permit tenure is to remain valid. If the seismic is acquired in late 2011, an exploratory well can be drilled as early as 2013. Following the first three-year phase, Bengal has the option to either relinquish the permit or commit to a subsequent three-year phase of work program. This second phase would involve the planning and drilling of a single offshore exploration well. The anticipated depth of this well test, as currently estimated, would be 2,600 metres from 400m water depth. To prudently manage costs throughout the expected work program, Bengal has been seeking one or more partners to help mitigate capital exposure and help the company accelerate its drilling plans on this important and highly prospective permit.

This permit is subject to the reservation of a 10% royalty to the Ashmore-Cartier Territory and Petroleum Resources Rent Tax (PRRT) to the Australian commonwealth.

Permit AC/P24

Bengal holds 10% working interest in exploration permit AC/P24 ("**AC/P24**") located in the Ashmore Cartier area offshore Australia. Bengal is partnered with PTTEP Australia Timor Sea Pty Ltd. (90% working interest), the operator. Bengal's interest was earned by the drilling of a discovery oil well at Katandra-1 in December 2004. AC/P24 comprises an area of 329 km^2 (gross 81,296 acres) and is penetrated by only the single Katandra-1 well. Though successfully demonstrating that recoverable light oil exists on the Katandra structure, the gross oil column penetrated by the Katandra-1 well, being 8 metres thick at the well, is insufficient at the present time to propose commercial development without further successful appraisal drilling. The operator applied for a new extension of the tenure period and subsequently received approval for the extension of the permit to October 7, 2011. The operator has recently re-applied to extend the permit to April 7, 2012 and is waiting for a response from the government.

The operator has proposed that a new exploratory well, Kingtree-1 be drilled on permit AC/P24 to a depth of approximately 1500 m from 105 m water depth in final fulfillment of the permit's current work-term obligations. The Kingtree-1 well will target a large untested structural feature located 14 km southeast of Katandra. This large Kingtree structure is located on the same horst trend as the productive Challis-Cassini oil field (located on trend southwest of the Kingtree prospect). From the most recent information supplied by the operator, Bengal anticipates that the Kingtree-1 well will cost, depending on whether the well must be directionally drilled, between $AUD 12 to 18 MM (net $AUD 1.2-1.8 MM to Bengal at 10% working interest). If successful, a subsequent field development plan will be proposed by the operator. Following the end of the permit term, tenure renewal for AC/P24 is possible in five-year increments with negotiation of additional work commitments between the operator and the regulatory authorities. Opportunity also exists to retain existing discoveries outside the exploration permit in the event of renewal.

This permit is subject to the reservation of a 10% royalty to the Ashmore-Cartier Territory and Petroleum Resources Rent Tax (PRRT) to the Australian commonwealth.

Cooper/Eromanga Basin, Onshore, Australia

Bengal has a very large acreage position across the onshore Cooper/Eromanga Basin of Australia approaching 2 million gross acres. Bengal's Cooper/Eromanga acreage is split among five separate blocks of land that are covered by: PEL 113, PEL 103A, ATP 732P, ATP 752P and ATP 934P.

Petroleum Exploration License PEL 113, Murteree, South Australia

Pursuant to the terms of a farm-in agreement, the Corporation earned a 35% interest in a 13,096 acre sub-block ("PEL 113M") of the larger Petroleum Exploration Licence 113 ("PEL 113") in the South Australian portion of the Cooper/Eromanga Basin. Bengal earned this interest by funding 3D seismic and subsequently funding the drilling of two wells operated by Stuart Petroleum Ltd.. PEL 113M is operated by Senex Energy Limited (65% working interest). Bengal has production from a single oil well, called Toparoa 1, covered by Petroleum Production License (PPL) 215, issued from PEL 113. The Toparoa 1 well has produced over 255,000 barrels of oil to date (32.67% net revenue to Bengal). The lands are subject to a 10% royalty to the Queensland government and a 1% royalty is reserved to the native title owners. Bengal retains the option to participate in any new wells drilled within defined area on the PEL offsetting PPL 215.

Bengal's net oil production at Toparoa for the year ended March 31, 2011 averaged 12 Bbls/d (down from 28 Bbls/d the year before). The lower average oil rate observed in comparison to last year is due to natural declines as well as shut-in and operational issues associated with unusual and record-setting flooding in the Australian outback desert of the Cooper Basin.

At Toparoa 1, an uphole zone that is present, called the Wyandra sandstone of the Cadna-owie Formation, tested clean light oil. With fracture stimulation, this uphole zone might be expected to produce oil at reasonable rates and if proved economic, additional drilling locations would follow in the near future. Probable reserves have been assigned to this Wyandra zone at Toparoa.

The Corporation's interest in this land is not subject to any further work commitments at present.

PEL 103A, Aspen, South Australia

Bengal formerly participated in the drilling of two unsuccessful exploration wells on Petroleum Exploration License ("**PEL 103**") in South Australia from which Bengal earned a 25% working interest in a 13,838 acre sub-block

("**PEL 103A**") of PEL 103. In 2008, Bengal chose not to exercise its option to earn an additional 25% working interest in another small sub-block on PEL 103. Consequently, Bengal has retained a 25% working interest in PEL 103A. PEL 103A is situated across much of an ancient geological structure called the Innamincka Dome.

In 2009, the operator agreed to conduct an evaluative work program PEL 103A to test the Innamincka Dome for coal seam gas (coal bed methane) in the shallow coals of the Cretaceous Winton Formation. The operator subsequently drilled three continuously-cored, stratigraphic test holes named Merninie 1, 2 and 3. Within PEL 103A, two test holes, Merninie 2 and 3 were drilled to depths 516 m and 600 m respectively in late October and early November 2009. The Winton coals appear to be low rank and thin in both wells. Unfortunately, the initial evaluation is that the Winton Formation is likely a sub-economic coal-seam-gas zone where it is located on the Innamincka Dome. The Corporation presently understands that no further coal seam gas evaluation is presently contemplated by the operator on the permit.

The lands are subject to a 10% royalty to the South Australia government, a 1% royalty reserved to the native title owners along with an encumbrance of 12% to third parties.

Authority to Prospect ATP 732P Tookoonooka, Queensland, Australia

Bengal completed the purchase of a 100% interest in ATP 732P and become the operator thereof following the formal grant of the permit by the Queensland Government in March 2011. Native title and cultural heritage agreements have already been arranged with the Boonthamurra aboriginal peoples enabling exploration activities on ATP 732P to commence. The initial four year term of the permit requires only a basic work commitment: basic geological work and seismic reprocessing, 100 km of new 2D seismic acquisition, and a single well. The ATP can be renewed twice for a total tenure period of twelve years subject to the negotiation of an additional work program. The land is subject to a 10% royalty payable on production to the Queensland government along with an added 1% royalty payable to the native title (aboriginal) persons.

Permit ATP 732P is very large in size (654,335 acres) and has been tested by only eight explorations wells to date. The permit is surrounded by existing Permian gas fields and Jurassic and Cretaceous oil fields. The block therefore has excellent oil potential from the shallow sequence and Bengal has also identified large prospective gas prospects in deeper Permian strata on the Permit. Thick coals interbedded with the Permian sands may also offer an associated coal-seam-gas opportunity. The center of the block was the site of what is believed to have been an ancient (Cretaceous) meteor impact structure. Such impact structures are known to be productive for oil and gas in other parts of the world.

In March 2011 the Corporation retained Ryder Scott Company Canada ("**Ryder Scott**") to prepare an independent Resource Evaluation Report (the "**Ryder Scott Resource Report**") pertaining to the lands situated within ATP 732P. Ryder Scott is an independent qualified reserves evaluator and the Ryder Scott Resource Report was prepared in accordance with the COGEH Handbook and NI 51-101. The effective date of the Resource Report is February 1, 2011.

The resource estimates presented in the Ryder Scott Resource Report are classified as undiscovered petroleum initially-in-place ("**Undiscovered PIIP**") and prospective resources. COGEH defines "Undiscovered PIIP" as that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. For greater clarity, the Ryder Scott Resource Report subdivides Undiscovered PIIP into undiscovered oil initially-in-place and undiscovered gas initially-in-place. COGEH defines "prospective resources" as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. The Ryder Scott Resource Report subdivides prospective resources into prospective oil resources, prospective gas resources and prospective condensate resources. The undiscovered hydrocarbon resource volumes and prospective resource volumes presented in the table below are unrisked. The term "unrisked" means that no geologic risk (chance of discovery) and no commercial risk (chance of development) have been incorporated in the hydrocarbon volume estimates.

The resource prospects evaluated in the Ryder Scott Resource Report are high risk exploration plays. No commercial hydrocarbons have been discovered to date on ATP 732P.

The Undiscovered PIIP that is the subject of the Ryder Scott Resource Report includes unrecoverable volumes and is not an estimate of the volume of the substances that will ultimately be recovered. In addition, there is no certainty that any portion of the resources that are the subject of the Ryder Scott Resource Report will be discovered. If discovered, there is no certainty that it will be commercially viable or technically feasible to produce any portion of such resources.

Low, best and high estimates are measures of the probability that the disclosed volumes could be exceeded. The low volume estimate is a measure whereby there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate of resources should hydrocarbons be discovered. The best volume estimate is a measure whereby there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate of resources should hydrocarbons be discovered. The high volume estimate is a measure whereby there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate of resources should hydrocarbons be discovered.

The Ryder Scott Resource Report attributes resources to ATP 732P in both the Cretaceous Wyandra and Permian Toolachee sandstones as follows:

Unrisked Estimates of Undiscovered PIIP and Prospective Resources on ATP 732P in the Cooper/Eromanga Basin, Queensland, Australia

	Low	**Best**	**High**
Wyandra Sandstone (Cretaceous)			
Undiscovered Oil Initially-in-Place (MMbbls)	60	111	187
Prospective Oil Resources (MMbbls)	13	24	41
Toolachee Sandstones (Permian)			
Undiscovered Gas Initially-in-Place (BCF)	663	1,224	1,879
Prospective Gas Resources (BCF)	496	916	1,415
Undiscovered Condensate Initially-in-Place (MMbbls)	25	80	201
Prospective Condensate Resources (MMbbls)	19	61	151
Toolachee Coals (Permian CBM)			
Undiscovered Gas Initially-in-Place (BCF)	491	923	1,454

Note:

(1) Undiscovered unrecoverable volumes are as follows: (i) Wyandra sandstones undiscovered unrecoverable oil 47, 87, 146 MMbbls, for low, best, high respectively; (ii) Toolachee sandstones undiscovered unrecoverable gas 167, 308, 464 BCF, for low, best, high, respectively; and (iii) Toolachee sandstones undiscovered unrecoverable condensate 6, 20, 50 MMbbls, for low, best, high, respectively.

The total Toolachee reservoir low volume estimate is an arithmetic sum of multiple estimates of low volumes and the Toolachee reservoir high volume estimate is an arithmetic sum of multiple estimates of high volumes, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as set forth herein.

It should also be noted that the Toolachee coals beds occur at depths of 1,500-1,800m, which is believed to be near the limit of known currently producing commercial coal bed methane gas ("**CBM**") projects. Therefore prospective CBM resources have not been assigned by Ryder Scott in the Permian Toolachee Formation.

Bengal has budgeted a seismic acquisition program of 450 km new 2D seismic and 50 km^2 of new 3D seismic, an amount greatly in excess of the actual required work commitments, to be undertaken in late 2011 so as to accelerate drilling activity and evaluation of the permit. The success of this program could enable drilling as early as late 2011 or the first half of 2012. The seismic the Corporation plans to acquire is concentrated first on the Permian gas plays plus a test area where a Cretaceous oil show was identified. In order to facilitate a large suite of potential drilling prospects and evaluate additional prospects, a large second round of 2D and 3D seismic will likely be planned for in 2012.

ATP 752P, Queensland, Australia

Bengal has multiple interests in ATP 752P. ATP 752P is located on the Cooper/Eromanga Basin and is subdivided into the Wompi Sub-Block (Bengal 22.5% working interest) and Barta Sub-Block (Bengal 25% working interest). However, Bengal retains the opportunity to increase its interests in the Wompi Sub-Block to 30% by drilling an option well and paying 60% of all drilling costs. Bengal has served notice of its intent to drill the Wompi option well. The option well is expected to be drilled before December 2012.

The end of the first four-year permit term of ATP 752P was July 31, 2010. The ATP was renewed for another four year term on July 1, 2010 and is renewable for another four year term after that, subject to negotiation of new work program commitments with the governmental authority and a partial block relinquishment. Pursuant to the expiry of the initial four year term Bengal, together with its joint venture partners, relinquished 33% of the ATP; the bulk of the relinquished area was assessed as poorly prospective or at least having very high exploration risk. The relinquishment does not affect any existing lead or prospects indentified by either Bengal or its partners. A new proposed work program was submitted to the applicable governmental authority, which program was planned as the minimum obligations necessary to validly hold the permit and includes additional seismic reprocessing, 50 km^2 of new 2D seismic acquisition and the drilling of a single exploration well. The anticipated drilling mandated under the ongoing farm-in agreement will potentially cover or exceed the proposed well commitments under the new work program. The joint venture partners are prepared, and have agreed, to accelerate activity beyond any minimal work program obligation as drilling success and results should warrant.

The Barta Sub-Block comprises 360,033 acres broken into north-eastern and south-western parcels as well as the 24,958 acre PL 303. The Cook oil field sits immediately east of the south-western parcel and an oil discovery (James-1) offsets the block's west boundary. Two wells drilled on the south-western parcel had oil shows. Existing and new seismic data has identified numerous, large, prospective structures on the sub-block.

Bengal increased its working interest in the Barta Sub-Block to 25% by funding 16.7% of the Cuisinier discovery well (the "**Cuisinier 1 Well**"), 83.3% of the second exploration well (the "**Hudson 1 Well**") and 55.0% of the third exploration well (the “**Barta North 1 Well**”). The first two of the initial Barta farm-in wells were drilled in 2008. The first well, Cuisinier 1 Well, was drilled and although found to be wet in the principal target zone, discovered oil in an uphole zone called the Murta sandstone member of the Mooga Formation, a zone previously not known to be productive in the area. The second, the Hudson 1 Well, proved wet and was abandoned.

In May 2010, production commenced from the Corporation’s Cuisinier 1 oil discovery. The company’s net production at Cuisinier 1 over the partial fiscal year 2010 was 9,649 Bbls (average 29 Bbls/d). The well continues to demonstrate a capability that is in excess of 400 Bbls/d oil (gross production) with no associated water. However, the Cuisinier 1 well suffered from significant shut-in periods through late 2010 and early 2011 due to limited oil storage facilities, and the trucking constraints imposed by extensive Cooper Basin flooding that occurred in the area. The operator is investigating improvements in oil storage and alternate trucking routes whereby increased oil sales are expected in 2011. Oil must be trucked from Cuisinier some distance through the outback to the Jackson oil field production facility for processing and before entering sales pipelines.

The Cuisinier 1 Well was the first well drilled on the Cuisinier structure. The Cuisinier structure is interpreted from 3D seismic data to be one of several culminations in the area. The producing interval is the Murta Sandstone, which is well developed with 8.7 m net pay over a 12metre interval (1,622 to 1,634 m depth). Cuisinier 1 is located approximately six kilometres west of the Santos operated Cook Oil Field in southwest Queensland, near the South Australian border. The adjacent Cook Oil Field produces oil from the prolific Hutton reservoir. The Hutton zone has not yet been found to be productive at Cuisinier. Another oil discovery (James-1) offsets the block's west boundary.

Pursuant to the original farm-in agreement, the operator has already acquired 103 km^2 of new 3D seismic (at no cost to Bengal) surrounding the Cuisinier discovery. On the basis of this new 3D seismic, the Barta North 1 Well and the Cuisinier 2 and Cuisinier 3 Wells were successfully drilled and cased as new potential oil wells. Testing results should be available in mid 2011. The new wells demonstrate that the oil discovered at Cuisinier 1 may now be targeted at significant depth below the proven Murta oil zone that was perforated in Cuisinier 1. Furthermore, the Barta North 1 Well indicates that additional Murta zone prospects can be successfully targeted across a greater reservoir fairway southwest and north of Cuisinier. The operator has proposed that 125 km^2 of additional new 3D seismic be acquired to extend the partnership's existing 3D seismic coverage northward from Cuisinier. The intent is to both pursue existing and generate new exploration leads and prospects for drilling in 2012. The operator has also indicated that an additional four Cuisinier development wells may be warranted in order to target pool areas believed to have better Murta reservoir quality based on the operator's detailed attribute analysis of the 3D seismic data. Though this analysis is still underway, new drilling at Cuisinier could occur as early as late 2011 or early 2012.

The Wompi Sub-Block comprises a total of 215,723 acres. Pursuant to the original farm-in agreement, the operator also has now completed the acquisition of over 200 km^2 of new 3D seismic over the Wompi Sub-Block of ATP 752P. The new 3D data (the Bowen and Genoa 3D surveys) has been processed, merged with previous 3D datasets and now interpreted by the operator. The operator has indentified two principle drilling locations that it wishes to pursue and anticipates drilling one of these wells prior to December 2011, under an amended farm-in agreement. Bengal's drilling costs will be fully carried on the first Wompi farm-in well. Bengal has also committed to drill on the Wompi Sub-Block where Bengal will pay 60% of all drilling costs. This option well is anticipated to be drilling prior to December 2012. Following the completion of the option well Bengal's working interest in the Wompi Sub-Block is expected to increase to 30%.

The land is subject to a 10% royalty payable on production to the Queensland government along with a 1% royalty reserved to the native title owners.

ATP 934P Barrolka, Queensland, Australia

Bengal and its partners were provisionally awarded a 361,268 acre onshore block of land located in the Cooper/Eromanga Basin in the State of Queensland, Australia. Bengal has a 50% working interest in the Authority To Prospect ("**ATP 934P**") block and is the operator. ATP 934P sits in the heart of the Cooper/Eromanga Basin and is surrounded by known gas fields. ATP 934P flanks the east margin of the giant Barrolka gas field. Recent activity west of ATP 934P has resulted in some new oil discoveries. Bengal believes that ATP 934P is prospective for deep basin-centered and tight gas prospects. To date, five undrilled structural leads have been identified as conventional gas drilling opportunities. Bengal and its partners have signed an interim agreement governing the lands and are working on a final joint operating agreement which is expected to be completed during 2011.

Bengal has successfully completed negotiations regarding native title on permit ATP 934P and has reached an agreement in principle, subject to formal signing of documents. Upon submission of the appropriate documents including environmental assessment, native title and cultural heritage agreements, the formal grant will be made. The Corporation believes the completion of such agreement and the formal grant of the permit may occur as early as late 2011, which would enable the commencement of exploration activities at that time. The work program on ATP 934P will entail at least 500 km^2 of new 2D seismic acquisition in year one, three wells in year two, and three wells or a combination of wells and seismic through years three and four. The exploration term only begins following the execution of a native title agreement and the formal grant of the ATP by the government. The ATP for ATP 934P can be renewed twice for a total tenure period of twelve years subject to the negotiation of additional work program.

The land will be subject to a 10% royalty payable on production to the Queensland government and management expects an additional royalty of approximately 1% to 1.75% subject to certain conditions will be reserved to the native title owners.

Cauvery Basin, Onshore India (CY-ONN-2005/1)

Bengal and its joint venture partners were awarded CY-ONN-2005/1 in December 2008 upon the signing of a PSC with the Government of India (the "**GOI")** on December 22, 2008. CY-ONN-2005/1 is located onshore in the Cauvery Basin, in the state of Tamil Nadu, India. Pursuant to a joint operating agreement, Bengal has a 30% working interest and is partnered with GSPC (30% interest) and GAIL (40% interest), the operator. CY-ONN-2005/1 measures 946 km^2 in area (233,760 gross acres). The State of Tamil Nadu awarded a petroleum exploration license in March, 2010. The permit CY-ONN-2005/1 is now currently within its second year work term. All available older 2D seismic data (732 km) has been reprocessed and additional interpretation work is underway by the operator. Under the minimum work program, 575 km^2 of new 3D seismic and 3 new exploration wells are required through the first four year phase of tenure, expiring March 2, 2014. The current year budgeted work program through to March 31, 2012, as approved by the joint venture partners, entails gross estimated expenditures of US$10.5 MM ($US 3.2MM net to Bengal) and includes acquisition and processing of 2,300 line kilometres of aeromagnetic data, an initial environmental impact review and the expanded acquisition of 700 km^2 of new 3D seismic (including a high resolution seismic survey). Identification and drilling of prospects is now anticipated prior to the end of 2013. These lands are subject to 12.5% royalty payable to the GOI on production**.** Bengal itself has identified basement highs, fluvial channel systems and reefal structures in this property through its own evaluation of existing 2D seismic data and the review of analog pools in this basin.

Cauvery Basin, Offshore India (CY-OSN-2009/1)

In October 2009, Bengal bid on and was awarded 100% working interest in exploration permit CY-OSN-2009/1 located in the offshore portion of the Cauvery Basin, in the Gulf of Mannar, State of Tamil Nadu, India. The block was acquired from bids submitted to NELP VIII on October 12, 2009. The Production Sharing Contract (PSC) with the GOI was formally signed in June 2010. The Indian State of Tamil Nadu granted a Petroleum Exploration License (PEL) for the CY-OSN-20009/1 block in August, 2010. The permit is granted for an initial (Phase 1) term of four (4) years, with three one-year extensions being available (three years total Phase 2) afterward. A royalty payment of 10% is due to the GOI on any successful production. In the event a discovery is drilled in waters deeper than 400 metres, the royalty to the GOI is reduced to 5%. The Phase 1 (permit years 1 through 4) work program entails a minimum 310 km of new 2D seismic and 81 km^2 of new 3D seismic acquisition. Phase 2 will require one exploratory well be drilled for each extension year that the block is retained. The permit measures 340,000 acres in size and despite its large size, has been previously tested by only 3 wells. Most of the permit sits in shallow waters. Bengal has itself identified a large seismically defined structure from the older existing 2D seismic data. The aerial extent of the newly mapped structure is significant and currently estimated to measure 18,750 acres. Subsequent to 2D data reprocessing, new 3D seismic is intended to be acquired as early as 2012 to help accelerate a future drilling program. In the block immediately adjacent to Bengal's block, the operator has committed to three new exploratory wells within the permit's initial four year term. In certain circumstances, success of any of these adjacent exploratory wells on the adjoining permit may prove up plays on Bengal's own permit.

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Corporation had a working interest as at March 31, 2011.

As at March 31, 2011, the Corporation had an interest in 8 gross (2.61 net) oil and natural gas wells as follows, all such wells are onshore wells.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Total	**2**	**0.58**	**3**	**0.75**	**2**	**0.78**	**1**	**0.50**
Canada	0	0	0	0	2	0.78	1	0.50
Australia	2	0.58	3	0.75	0	0	0	0

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2011.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Total	**26,458**	**15,151**	**3,139,457**	**2,254,641**	**3,166,555**	**2,269,792**
Canada	1,920	796	-	-	1,920	796
Australia	25,178	14,355	2,565,695	1,844,513	2,590,873	1,858,868
India	-	-	573,762	410,128	573,762	410,128

Note:

(1) Bengal calculates both its gross and net acres on a per lease basis.

The Corporation does not expect that any rights to explore, exploit or develop its current oil and gas acreage will necessarily expire before March 31, 2012, unless the corporation should deem such relinquishment as appropriate or prudent.

Forward Contracts and Marketing

Although Bengal has no set policy, management of Bengal may use financial instruments to reduce corporate risk in certain situations. Risk management policies will be developed over time as Bengal builds a production base to support sustainable growth. Management will further develop a strategy over time to hedge existing liquids and natural gas production to help protect a base development capital program, guarantee a return or to facilitate financings when concluding a business transaction. Currently, Bengal has no hedging commitments due to the nature of its current asset portfolio**.**

Additional Information Concerning Abandonment and Reclamation Costs

Estimated future abandonment costs related to a property have been taken into account by DeGolyer in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. The Corporation uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at March 31, 2011, the Corporation had 0.75 net wells for which it expects to incur zonal abandonment costs. The total abandonment and reclamation costs as at March 31, 2011 in respect of proved and probable reserves using forecast prices is $289,000 (undiscounted) and $139,000 (discounted at ten percent). One hundred percent of such amounts were deducted as abandonment and reclamation costs in estimated future net revenues of Bengal in respect of proved and probable reserves as disclosed above. The following table sets forth abandonment costs deducted in the estimation of the Corporation's future net revenue:

Forecast Prices and Costs (MM$)	Total Proved	Total Proved plus Probable
Year	Abandonment Costs (Undiscounted)	Abandonment Costs (Undiscounted)
2012	-	13
2013	49	36
2014	-	-
Thereafter	96	240
Total Undiscounted	**158**	**289**
Total Discounted @ 10%	90	139

Bengal expects to pay approximately $49,000 in the next three financial years in respect of its abandonment and reclamation costs.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2012 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2016 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended March 31, 2011:

	Canada (M$)	Australia (M$)	India (M$)	Total (M$)
Property acquisition costs- Proven	-	-	-	-
Property acquisition costs- Unproven	-	991	-	991
Exploration:				
Geological and Geophysical	37	786	226	1,049
Drilling	-	1,135	-	1,135
Completions	-	131	-	131
Exploration Subtotal	37	2,052	226	2,315
Development:				
Geological and Geophysical	-	-	-	-
Drilling	-	637	-	637
Completions	-	-	-	-
Development Subtotal	-	637	-	637
TOTAL EXPENDITURES	**37**	**3,680**	**226**	**3,943**

Notes:

(1) The numbers in this table may not add due to rounding.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended March 31, 2011:

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
TOTAL	**1**	**0.25**	**2**	**0.50**
Canadian Properties				
Light and Medium Oil	-	-	-	-
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total Canadian	-	-	-	-
Australian Properties				
Light and Medium Oil	1	0.25	2	0.50
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total Australian	1	0.25	2	0.50

In the fiscal year ended March 31, 2011, the Corporation participated in the drilling of 3 (net 0.75) oil wells. No other drilling was undertaken. Bengal decreased its net exploration acreage by 2% through mandatory relinquishments and a lease expiry for a South Larne permit in Northern Ireland with respect to ATP 725P.

Canada

No new activity occurred on the Oak property in British Columbia. Bengal sold its entire interest in the Kaybob gas property for cash in September 2009.

Australia

Please see "General Development of the Business – Fiscal Year Ended March 31, 2011", "General Development of the Business – Recent Developments" and "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties" for a summary of the current and expected exploration and development activities for Bengal's Australia properties.

Barta Block - ATP 752P

In 2010, the company fulfilled its earning obligations on the Barta Sub Block by funding 55% of the cost of the Barta North 1 Well. Bengal now holds a 25% non-operated working interest in the greater Barta Sub Block and the existing Cuisinier 1 Murta-zone oil discovery. The Cuisinier 1 Well began production in May 2010 and has produced over 63,000 Bbls of oil to April 30, 2011 with no appreciable water-cut. The well's productive capability continues to be in excess of 350 BOPD of 52° API (88 BOPD net to Bengal). Production is stored at surface however due to the remote location, must be trucked to a pipeline terminal near Jackson for sales. The well has been produced intermittently over the last few months due to logistical problems related to severe flooding in late 2010 and early 2011 in central Australia. The operator is investigating additional tank storage options to improve oil sales and mitigate downtime at the Cuisinier 1 Well. Improvements are being seen by the operator. The operator reported that 10,481 barrels of oil were delivered for sale in April, averaging 340 bopd on a calendar-day basis (net 85 bopd to Bengal) over the month.

The Cuisinier 2 and Cuisinier 3 Wells were drilled offsetting the Cuisinier 1 Murta-zone oil discovery. The Cuisinier 2 Well was drilled approximately 450m northeast of the Cuisinier 1 Well and encountered three separate Murta pay sands to a depth 27m below the perforations at the Cuisinier 1 Well. Swab results from the lowest pay sand recovered 95 Bbls oil over approximately a 6 hour swab period. The upper Murta zones, including the equivalent pay zone at the Cuisinier 1 discovery, showed poor inflow and may require reservoir stimulation before they can produce. Analysis of test results is required and full completion results are expected from the operator in mid 2011. The Cuisinier 3 Well was drilled 700m southwest from Cuisinier 1. Cuisinier 3 encountered two apparent log-pay sands. Early swabbing results from the lower sand recovered a combination of oil and water. The origin and nature of the water recovery is as yet undetermined. Swabbing of the upper Murta pay sand, the equivalent to the producing Murta pay sand in Cuisinier 1, recovered 37 Bbls of oil over an approximately 5 hour period (mechanical difficulties prevented full evaluation). The swab results require further analysis. Again, it is expected the operator will provide a full report and analysis of the completion in mid 2011. Both Cuisinier 2 and 3 appraisal wells appear that they will be productive oil wells although it remains too early to determine their true productive oil rates before they are placed on pump.

The well results at Cuisinier indicate at least a 19m gross oil column exists within the original upper Murta discovery zone. Additional deeper, lower Murta oil pay, as has been demonstrated at Cuisinier 2, looks to extend at least an additional 21m deeper. The different Murta pay zones may prove to have different oil-water contacts. Further analysis and appraisal drilling is required to determine and more fully understand the extent of the oil discovered to date.

The Barta North 1 Well was drilled approximately five km southwest of Cuisinier 1 on what was mapped as a separate structure. The well was cased by the operator as a potential oil producer with an apparent 5m gross log-pay zone. Completion and testing is expected late in calendar Q2 2011 or early in calendar Q3 2011 to verify the log results and productive capability of the well. The Barta North 1 Well demonstrates that oil has migrated through a large fairway of varying quality Murta reservoir and therefore indicates that numerous additional exploration plays and leads can be found from which to target the Murta sandstone over a very large area of the Barta Sub-Block. The operator has proposed that an additional 125 km^2 of 3D seismic be shot to extend the existing 3D seismic coverage northward from Cuisinier in order to pursue and generate new exploration leads and prospects.

As a condition of permit ATP 752P moving into the second of three (four year) terms, one third of the original permit area was mandatorily relinquished. However, the portion of the Barta Sub Block that was retained remains very large (1,457.1 km^2). Bengal now holds a 25% working interest in the Barta Sub-Block. The permit is valid for another eight years to July 31, 2018. The expected work commitments as applied for under the second permit term entail 100 km 2D seismic reprocessing, 50 km of new 2D seismic and a single exploration well. The government's confirmation of the application for the work program remains pending, however, the exploration activity undertaken thus far since July 31, 2010 will likely prove in excess of the required work program necessary to hold the permit in good standing.

AC/P47

Bengal completed its seismic reprocessing efforts and managed its first year work program regarding permit AC/P47 in the Timor Sea. Planning for a 750 km^2 new 3D survey in the second year work program has commenced, but the 3D acquisition has not been undertaken. Instead the Corporation has sought to find a partner or prospective farmee for the permit in order to mitigate the company's capital exposure and ultimately, to better possibly accelerate drilling on the permit. Bengal currently still holds a 100% working interest in AC/P47. The permit and associated prospects have been marketed by IndigoPool (Schlumberger). It remains too early to judge the ultimate success of these ongoing marketing efforts. In the meantime, Bengal has sought approval for the variation in the timing of its mandated work program by application to the Ashmore-Cartier (Northern Territory) and Australian Commonwealth regulatory authorities. Formal response from the regulators and the approval of applied for changes on the timing of the work program are anticipated now sometime in mid 2011. Subject to these regulatory approvals, and as to whether a partnership or farm-out can be arranged, the company will endeavour to see that the new 3D seismic survey will be acquired on AC/P47 very late in 2011 or early in 2012. If the seismic is acquired in late 2011, an exploratory well could be drilled as early as 2013.

India

Please see "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a summary of the current and expected exploration and development activities for Bengal's Indian properties.

Production Estimates

The following tables disclose, by product, the total volume of the Corporation's gross production estimated by DeGolyer for the fiscal year ending March 31, 2011 for year 2011.

From Gross Proved Reserves:	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Total	**53**	**-**	**320**	**3**	**109**	**100**
Canadian Properties -Oak	-	-	320	3	56	51
Australian Properties:						
Cuisinier	43				43	40
Toparoa	10				10	9

Note:

The numbers in this table may not add exactly due to rounding.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended			
	2011	2010		
	March 31	Dec. 31	Sept. 30	June 30
Average Daily Production[1]				
Total				
Oil (BOE/d)	56	36	36	27
Natural Gas Liquids (BOE/d)	3	3	4	4
Natural Gas (Mcf/d)	348	327	366	381
Total (BOE/d)	**117**	**94**	**101**	**94**
Canadian Properties				
Natural Gas Liquids (BOE/d)	3	3	4	4
Natural Gas (Mcf/d)	348	327	366	381
Total (BOE/d)	61	58	65	67
Australian Properties				
Oil (BOE/d)	56	36	36	27
Total (BOE/d)	56	36	36	27
Average Price Received (net of transportation)				
Total				
Oil ($BOE/d)	109.06	92.32	73.00	83.66
Natural Gas Liquids ($BOE/d)	60.40	42.57	42.63	65.63
Natural Gas ($Mcf/d)	3.96	3.72	3.81	3.60
Total ($BOE/d)	**65.49**	**49.93**	**41.59**	**40.92**
Canadian Properties				
Natural Gas Liquids (BOE/d)	60.40	42.57	42.63	65.83
Natural Gas (Mcf/d)	3.96	3.72	3.81	3.60
Total ($BOE/d)	25.69	23.46	24.10	23.91
Australian Properties				
Oil ($BOE/d)	109.06	92.32	73.00	83.66
Total ($BOE/d)	109.06	92.32	73.00	83.66
Royalties Paid				
Total				
Oil ($BOE/d)	9.43	7.82	6.90	7.81
Natural Gas Liquids ($BOE/d)	13.92	9.45	9.28	12.10
Natural Gas ($Mcf/d)	0.50	0.34	0.43	0.15
Total ($BOE/d)	**6.38**	**4.31**	**4.38**	**3.30**
Canadian Properties				
Natural Gas Liquids ($BOE/d)	13.92	9.45	9.28	12.10
Natural Gas ($Mcf/d)	0.50	0.34	0.43	0.15
Total ($BOE/d)	3.59	2.48	2.98	1.51
Australian Properties				
Oil ($BOE/d)	9.43	7.82	6.90	7.81
Total ($BOE/d)	9.43	7.82	6.90	7.81

	Quarter Ended			
	2011	2010		
	March 31	Dec. 31	Sept. 30	June 30
Operating Expenses				
Total				
Oil ($BOE/d)	40.91	29.93	33.94	36.11
Natural Gas and NGLs ($BOE/d)	16.14	17.04	18.27	14.93
Total ($BOE/d)	**27.97**	**21.99**	**23.88**	**20.96**
Canadian Properties				
Natural Gas and NGLs ($Mcf/d)	2.69	2.84	3.05	2.43
Total ($BOE/d)	16.14	17.04	18.27	14.93
Australian Properties				
Oil ($BOE/d)				
Transportation	17.21	17.19	16.29	15.73
Operating Expenses	23.70	12.74	17.66	20.37
Total ($BOE/d)	40.91	29.93	33.94	36.11
Netback Received[(2)(3)]				
Total				
Oil ($BOE/d)	58.69	53.67	32.16	39.73
Natural Gas and NGLs ($BOE/d)	5.95	3.34	2.86	7/47
Total ($BOE/d)	**31.13**	**22.69**	**13.33**	**16.65**
Canadian Properties				
Natural Gas and NGLs ($Mcf/d)	0.99	0.56	0.48	1.24
Total ($BOE/d)	5.95	3.34	2.86	7.47
Australian Properties				
Oil ($BOE/d)	58.69	53.67	32.16	39.73
Total ($BOE/d)	58.69	53.67	32.16	39.73

Notes:

(1) Before deduction of royalties.
(2) Amounts from physical gas contracts are included in the gas prices shown.
(3) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues. GCA is excluded.

The following table indicates the Corporation's average daily production from its important fields for the year ended March 31, 2011:

	Light and Medium Crude Oil	Heavy Oil	Gas	NGLs	BOE
	(Bbls/d)	(Bbls/d)	(Mcf/d)	(Bbls/d)	(BOE/d)
Total	**39**	**-**	**353**	**4**	**101**
Cuisinier and Toparoa	39	-	-	-	39
Oak	-	-	353	4	62

Note:

(1) Natural gas volumes are non-associated sales gas volumes.
(2) The totals shown above may not match the corporate totals due to rounding.

The Corporation's production for the year ended March 31, 2011 was 49% light quality crude oil (32° API or greater), 0% heavy oil, 49% natural gas, and 2% liquids.

For the twelve months ended March 31, 2011, approximately 70% of the Corporation's gross revenue was derived from crude oil production and 30% was derived from natural gas and natural gas liquids production.

DIVIDEND POLICY

Bengal has not paid any dividends on outstanding Bengal Shares. The Board of Directors of Bengal will determine the actual timing, payment and amount of dividends, if any, that may be paid by Bengal from time to time based upon, among other things, the cash flow, results of operations and financial condition of Bengal, the needs for funds to finance ongoing operations and other business considerations as the Board of Directors of Bengal considers relevant. Payment of dividends is subject to the consent of the Corporation's lenders.

DESCRIPTION OF CAPITAL STRUCTURE

Bengal is authorized to issue an unlimited number of Common Shares, of which 51,961,349 are issued and outstanding as of the date hereof, and an unlimited number of preferred shares ("**Preferred Shares**"), of which none are issued and outstanding as of the date hereof. There are 940,000 Performance Warrants issued and outstanding. Each Performance Warrant is exercisable for one (1) Common Share at an exercise price of $2.00 per share and vest as to one third on each of the first, second and third anniversaries of issuance or immediately upon becoming exercisable. The warrants will become exercisable only at such time as the twenty (20) day trailing weighted average trading price of the Common Shares on the TSX reaches $4.00 and expire on August 13, 2011. There are 2,748,667 employee stock options outstanding with an average exercise price of $1.21 of which 1,649,673 are vested.

The holders of Common Shares are entitled to receive notice of, to attend and vote at any meetings of the Shareholders, to receive such dividends declared by Bengal and to receive the remaining property of Bengal on dissolution after creditors of Bengal and holders of any Preferred Shares outstanding at the time have been satisfied.

The Preferred Shares are issuable in series, with each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of Bengal, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of each series. The Preferred Shares do not have the right to vote at meetings shareholders, except as may be provided for under applicable law.

MARKET FOR SECURITIES

Trading Price Volume

The Bengal Shares are listed and posted for trading on the TSX under the symbol "BNG". The following sets forth the price range and trading volume of the Bengal Shares (as reported by such exchange) for the periods indicated.

Period	High ($)	Low ($)	Volume
2010			
March	1.45	1.11	343,204
April	1.72	1.30	263,390
May	1.39	1.05	205,714
June	1.44	1.02	244,760
July	1.28	1.04	216,202
August	1.17	0.92	175,150
September	1.15	0.92	619,340
October	1.36	1.02	1,382,701
November	1.23	1.00	2,525,760
December	1.39	1.00	4,886,835
2011			
January	1.55	1.22	2,510,023
February	2.33	1.43	7,383,796
March	2.25	1.62	4,371,916
April	2.06	1.57	2,165,731
May	1.63	1.36	1,959,608
June	1.51	1.03	1,484,492
July (1-11)	1.44	1.19	504,901

Prior Sales

During the year ended March 31, 2011 Bengal issued 640,000 options to acquire Common Shares at an exercise price of $1.39 and an additional 20,000 options at an exercise price of $2.16. No additional unlisted securities were issued during the year ended March 31, 2011.

Escrowed Securities

As of March 31, 2011 no securities of the Corporation were subject to escrow.

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
Chayan Chakrabarty Calgary, Alberta, Canada	President, Chief Executive Officer and Director	February 13, 2008	Appointed Chief Executive Officer of Bengal November 26, 2010. President of Bengal since February 13, 2008. Vice President, International with Daylight Resources Trust previously Sequoia Oil & Gas Ltd. from February 2006 to November 2007. .

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
Ian J. Towers [2] [3] Calgary, Alberta, Canada	Director (Chairman)	November 24, 2005	President, Chief Executive Officer and Director of Dolomite Energy Inc., a private oil and gas company, since February 2005.
Richard Bonnycastle[1] Calgary, Alberta, Canada	Director	August 27, 2010	Chairman and President of Cavendish Investing Ltd. (a private investment company) from 1968 to present. Self-employed investor and financial consultant from 1968. Current Director of various private and public companies.
Richard Edgar [2] Calgary, Alberta, Canada	Director	November 14, 2002	President of Poplar Creek Resources since July 2009. Director of Shelton Petroleum AB since December 2009. Chairman of Shelton Canada Corp. from June 1998 to Dec. 2009. Executive Chairman of Arrow Energy Ltd. from April 2008 to April 2009. Prior thereto, President of Avery Resources Inc. from November 2005 to February 2008.
Peter D. Gaffney [2] [3] Alton, Hampshire, United Kingdom	Director	January 30 2011	Independent advisor to international oil and gas industry. Director of Dominie Enterprises Ltd. from November 2005 to present. Director of Gaffney, Cline & Associates Services from 1987 to December 2009. Senior partner and Director of Gaffney, Cline & Associates Ltd. from 1963 to April 2008.
James B. Howe [1] Calgary, Alberta, Canada	Director	November 24, 2005	From January 1982 to present, President of Bragg Creek Financial Consultants Ltd. (a private financial consulting corporation). Mr. Howe is a Director of various public companies including Pason Systems Ltd., Ensign Energy Services Ltd., Wrangler West Energy Inc., Seaview Energy Inc. and Holloway Lodging Real Estate Investment Trust.
Robert Steele [1] [3] Calgary, Alberta, Canada	Director	August 27, 2010	Independent businessman. Recently joined the Board of Directors of Global Energy Services. Director of Skywest Energy Ltd. since June 22, 2010. From 2001 to the May 2011 sale a Director of Technicoil Corporation. Chairman and Chief Executive Officer of Berens Energy Ltd. from February 2002 to March 2010.
Bryan Goudie Calgary, Alberta, Canada	Chief Financial Officer	N/A	Chief Financial Officer of Bengal since April 2006.
Jim Mott Calgary, Alberta, Canada	Vice President, Exploration	N/A	Vice President, Exploration of Bengal since February 13, 2008. Prior thereto Mr. Mott was a principal of Primordial Energy Ltd. from September 2003 to January 2008.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.

(3) Member of the Compensation Committee.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at July 12 2011, the directors and officers of Bengal set forth above, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 5,361,288 Bengal Shares or approximately 10.3% of the issued and outstanding Bengal Shares and 16% on a fully diluted basis.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed herein, no director or executive officer of the Corporation: (i) is, or has been in the last 10 years, a director, chief executive officer or chief financial officer of an issuer (including the Corporation) that, (a) while that person was acting in that capacity was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the proposed director ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer, (ii) is, or has been in the last 10 years, a director or executive officer of an issuer (including the Corporation) that while that person was acting in such capacity or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (iii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver, receiver manager or trustee appointed to hold his or her assets; or (iv) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in deciding whether to vote for a proposed director.

Mr. Edgar was a director of Shelton Canada Corp. which company was listed on the TSX Venture Exchange. Shelton Canada Corp. was suspended from trading for failure to file its 2008 annual financial statements within the timeframe allowed. Shelton Canada Corp. has since filed its annual financial statements and was relisted in June 2009 and subsequently delisted January 4, 2010.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Schedule "C".

Composition of the Audit Committee

The members of the Audit Committee are James Howe (Chairman), Richard A. N. Bonnycastle and Robert Steele. The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate. The following is a description of the education and experience of each member of the Audit Committee.

Mr. James Howe, Chairman

Mr. Howe is a Chartered Accountant and currently serves on the Board of Directors, including Audit Committees, for various public companies. Mr. Howe graduated from the University of Western Ontario with a Bachelor of Arts (Honours) in Business Administration in 1973.

Mr. Richard A. N. Bonnycastle

Mr. Bonnycastle graduated from the University of Manitoba with a Bachelor of Commerce in 1956. He is a self-employed investor and financial consultant. He is currently Chairman and President of Cavendish Investing Ltd. and serves on the Audit Committee for both Century Energy Ltd. and Pacific Iron Ore Corporation. He has served on the Boards of Directors for numerous other private and public companies.

Mr. Robert Steele

Mr. Steele graduated in Electrical Engineering from the University of Saskatchewan in 1970. Mr. Steele is a professional engineer and independent businessman. He currently sits on the Board of Directors and Audit Committee of Skywest Energy Ltd. and more recently has joined the Board of Directors of Global Energy Services (TSXV:GLK). He served on the Board of Directors for Technicoil Corporation until the May 2011 sale and also served as both Chairman of the Board and Chief Executive Officer of Berens Energy Ltd..

Pre-Approval of Policies and Procedures

Pursuant to the requirements of the Audit Committee charter, the Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services as described in the Audit Committee Mandate and Terms of Reference as set forth in Schedule "C" attached hereto.

External Auditor Service Fees

	Financial Year Ending 2011	Financial Year Ending 2010
Audit Fees	$90,000	$120,000
Audit Related Fees	$78,500	$-
Tax Fees	$15,750	$20,395
All Other Fees	$-	$ 6,500

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

HUMAN RESOURCES

As at March 31, 2011, Bengal employed seven (7) full-time employees at the head office**,** and five (5) part-time consultants. Bengal intends to add additional professional and administrative staff as the need arises.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

Valiant Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Bengal Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that Bengal is or was a party to, or that any of its property is or was a subject of, during the last completed financial year that were or are material to the Corporation, nor are any such material legal proceedings known to Bengal to be contemplated, that were material.

During the year ended March 31, 2011, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Corporation entered into with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation or any of its subsidiaries.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), neither the Corporation nor any of its subsidiaries has entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than DeGolyer, the Corporation's independent engineering evaluators, Ryder Scott, the independent reserves evaluators that performed the Ryder Scott Resource Report, and KPMG LLP, the Corporation's auditors. None of the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of National Instrument 51-102 of the Canadian Securities Administrators) of DeGolyer or Ryder Scott, as applicable, have or are to receive any registered or beneficial interest, direct or indirect, in any of Bengal's securities or other property of Bengal or of Bengal's associates or affiliates, either at the time DeGolyer or Ryder Scott, as applicable, prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP, Chartered Accountants, the Corporation's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and foreign countries, such as India and Australia, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry**,** in the areas in which the Corporation has operations.

Pricing and Marketing

Canada:

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

India *- Oil and Natural Gas*

Under the terms of the PSCs to which the Corporation is a party, the Corporation is required to sell all of its oil to the GOI in order to meet total national demand. The oil price is determined by reference to an internationally recognized crude oil of similar properties and adjusted for differences in specific gravity and impurities. Natural gas is to be sold into the Indian domestic market at competitive fair market arm’s length prices. The Corporation has the right to invest and repatriate foreign currency freely.

Australia *– Market Conditions*

There is a free market for oil, condensate and liquid petroleum gas in Australia. As a result, there are no price controls and export or import approvals are not required. Markets for crude oil and condensate exist in Australia and low-sulphur light crude oil finds a ready domestic and overseas market.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in areas where the Corporation has production and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spudded between December 1, 2003 and September 1, 2009;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth;

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated $120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spudded between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Australia

The maximum government royalty on oil and gas production in Australia is 10%, which is at the low end of international oil and gas taxation and less than Canada and the United States. The royalty is based on gross revenue less an allowance for certain operating expenses and capital. In onshore areas that are effected by native title, and which have been awarded since the mid-1990s, an additional royalty to recognized indigenous Australian title holders is applicable. This royalty is negotiable and generally varies between 1-2%.

India

In case of onshore blocks, the royalty payable to the appropriate state government is 12.5% of the well-head value of crude oil and natural gas. For offshore blocks, the royalty payable to the GOI is 10% of the well-head value of crude oil and natural gas. A PSC with the GOI will provide, among other things, for the sharing of the production from profitable wells drilled on the basis of accumulated net income to accumulated investment as a ratio. This ratio determines the portion of production attributable to the government which is determined on a year by year basis**.** All royalty payments paid to the GOI or a state government are included under costs that are considered allowable for cost recovery purposes under a PSC with the GOI.

Land Tenure

Canada

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

The province of British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Australia

For the most part, mineral ownership in Australia is governed by the respective state governments who grant tenements for the exploration of petroleum and natural gas. While not exactly the same, largely the process from state to state is similar. Oil and gas companies typically submit applications for exploration permits or an ATP in response to invitations to bid made in government gazettals (onshore and offshore). Within the applications, companies outline a schedule of work programs which include both an estimate of the financial commitments to be spent on the property(s) year over year along with a certain amount of seismic and/or exploration wells to be drilled. Depending on the location of the permit, state governments will award the permits subject to the Corporation successfully negotiating with Aboriginal surface owners. After a successfully negotiated native title agreement, the Corporation is then granted the ATP by the State. The permits provide the Corporation with at least four (4) years to conduct its proposed work program with the opportunity for potential extensions. It is usual for each state government to reserve unto itself a royalty which runs with the life of the tenement documents. It should also be noted that for each ATP or exploration permit issued there is a minimum work program which the applicable state authority expects to be met or exceeded. If the minimum work commitment set forth in the work program is not completed then there is a risk that the ATP or exploration permit is terminated.

In most cases ATP's are granted for a period of twelve years. The twelve years are subdivided into three, four year periods. During the first four year period, work commitments are completed and at the end of the period one third of the land that was originally granted must be relinquished back to the state upon which the next four year period commences.(8.325% relinquishment per year). At the end of the twelfth year, all of the land will have been relinquished that has not been a part of a commercial discovery. Commercial discoveries are held under Production Licenses' which are exempt from relinquishment and stay active until final field abandonment.

India

The oil and gas industry in India is subject to extensive regulations governing its operations including land tenure, exploration, development, production, refining, transportation and marketing through legislation enacted by various levels of government. Although the GOI has ultimate ownership and responsibility for oil and gas operations, various state governments also have input into the industries activities. During the past several years, GOI regulations have been revised to include tax holidays and permit foreign ownership levels of up to one hundred percent in the Indian oil and natural gas industry. In response to invitations to bid made by the GOI through the New Exploration Licensing Policy ("**NELP**") bid rounds in India, domestic and international oil and gas companies submit bids to win tenements for the exploration of petroleum and natural gas. Within the bid applications, companies outline a schedule of work activities along with an estimate of associated financial commitments on each tenement on an annual basis; in addition, companies submit a fiscal package which offers the economic terms under which a company would operate the tenement. The fiscal or economic terms and the duration of the land tenure are confirmed at the time of signing a PSC between a company and the GOI. Most PSCs in India grant the companies 20-25 year tenure with a provision for up to two 5 year extensions.

Most PSC's in India grant the companies multiple year tenure and in some cases the ability to be granted extensions. There is usually an Initial Exploration Period and at the end of it and after having conducted a minimum work program the company may relinquish its entire interest or continue with a subsequent Exploration Period. As in Australia, commercial discoveries are held through the production phase and no relinquishments are required.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

The Corporation is subject to significant environmental and other regulations in respect of its exploration activities in Australia and India and has tried to earnestly undertake its operations in an environmentally responsible manner and to maintain compliance with the relevant regulations. Rehabilitation of individual field projects is completed progressively to ensure necessary rehabilitation restoration is kept to a minimum at any particular time.

Management is satisfied that no material breaches of the environmental legislation have occurred with respect to any of the Corporation's properties. No notices of any material breaches have been received from any authority by the Corporation.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 BOE/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009 and $20 per tonne of CO_2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

To the knowledge of the Corporation, there is no ownership or working interests in facilities that are subject to reporting/verification requirements.

RISK FACTORS

Bengal cannot guarantee its ability to obtain the required consents, waivers and extensions from the Director General of Hydrocarbons or Government of India as and when required to maintain compliance with the Corporation's PSCs. Any delays experienced in receiving those consents, waivers and extensions may result in liabilities incurred under the PSCs for failure to maintain compliance with and timely completion of the related work programs, or that the Corporation's partners may not be successful in its efforts to obtain payment from Bengal on account of exploration costs it has expended for which they assert the Corporation is liable or otherwise seek to hold it in breach of that PSC or commence arbitration proceedings against the Corporation.

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances 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.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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, labour disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Corporation'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 any significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductable under applicable laws or may have differing views as to values of transfer 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 Corporation having to pay significant penalties and fines. Furthermore, in the event of a dispute arising from international operations, the Corporation 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. The Corporation operates in such a manner as to minimize and mitigate its exposure to these risks; however, there can be no assurances that Bengal will be successful in protecting itself from the impact of all of these risks.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as 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.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Variations in Foreign Exchange Rates and Interest Rates

Bengal receives Canadian dollars for gas sales from its Oak property. These Canadian dollars are then expended on operations and administration in Canada. The Corporation's expenses on Canadian operations are denominated in Canadian dollars and the Corporation's operating income is therefore not generally impacted by the Canadian to US dollar exchange rate.

The exchange rate for the Australian dollar has improved against the Canadian dollar throughout the year. Bengal, through its subsidiary Avery Resources (Australia) Pty Ltd., received revenue from Australian oil sales in US dollars. These US dollars are then converted to Australian dollars and remain in Australian dollars until expended on operations or capital in Australia and therefore the Australian dollar to Canadian dollar exchange rates do not materially impact the Corporation's overall profitability. Historically, declines in world oil prices which are denominated in US dollars have been offset by increases in the value of the Australia versus the US dollar. As a result, Bengal's Australian netbacks are not overly affected by the Australian dollar to US dollar exchange rates.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate. While Bengal may employ hedging when it believes it prudent to do so, there is no assurance that it will do so in any particular circumstance. The Corporation does not use any of these derivative instruments at this time.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation 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 the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is 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, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Some of Bengal's oil and gas interests are in offshore properties. Offshore operations involve a significant degree of risk including all of the risks associated with all petroleum operations which can be magnified due to operating in remote offshore locations. Fires and explosions on drilling rigs and other offshore platforms are more likely to result in personal injury, loss of life and damage to property due to the remote locations and time required for rescue personnel to get to the locations. Blow-outs and spills are more likely to result in significant environmental damage to the marine environment, can be difficult to contain and difficult and expensive to remediate. Although Bengal intends to operate in accordance with all recommended and required health, safety and environment practices, which will reduce such risks, there can be no assurance that these risks can be avoided. The occurrence of any of these events could have a materially adverse effect on the Corporation.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Bengal has entered into agreements with respect to various permit areas in Australia. The formal grant of some of these permits by Australian government authorities is conditional on and subject to the successful conclusion of Native Title negotiations. Accordingly, there is a risk that the native claims may not be resolved and the permits may not be issued.

There are no such aboriginal claims in India.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Australia

All phases of the oil and gas exploration, development and production activities are regulated in varying degrees by the Australian government, either directly or through one or more governmental entities. The areas of government regulation include matters relating to restrictions on production, price controls, export controls, income taxes, expropriation of property, environmental protection and rig safety. In addition, the award of an ATP or PEL and matters relating to the implementation and conduct of operations under these agreements are subject to the consent of the Australian government. All future drilling and production programs and by the Corporation in Australia must also be approved by the Australian government. This regulatory environment and possible delays inherent in that environment may increase the risks associated with the Corporation's exploration and production activities and increase the Corporation's costs of doing business.

India

All phases of the oil and gas exploration, development and production activities are regulated in varying degrees by the Indian government, either directly or through one or more governmental entities. The areas of government regulation include matters relating to restrictions on production, price controls, export controls, income taxes, expropriation of property, environmental protection and rig safety. In addition, the award of a PSC and matters relating to the implementation and conduct of operations under the PSC are subject to Government of India consent. As a consequence, all future drilling and production programs and by the Corporation in India must be approved by the Indian government. This regulatory environment and possible delays inherent in that environment may increase the risks associated with the Corporation's exploration and production activities and increase the Corporation's costs of doing business.

The Corporation and its partners are required under the NELP fiscal regime to submit annual expenditure budgets to the Government of India for approval on all Indian fields and blocks. Expenditures in excess of the budget are subject to approval by the Government of India. In the case of cost over-runs, those expenditures not ratified by the

Government of India, the allowable expenditure limit for any given year may be reduced and this would affect the investment multiple, potentially affecting the petroleum profit share calculation.

The Corporation will be required to submit a bank guarantee of the first year's estimated expenditure.

The Corporation has performance security guarantees to the Government of India. The Government of India has the right to collect on the guarantees if the Corporation does not carry out the work commitment required under the various concession agreements (PSC's).

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In both India and Australia the level of activity and production may be influenced by seasonal weather fluctuations such as, but not limited to, flooding and monsoons. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Environmental

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 Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation 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 any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

India

The PSCs contain certain terms that may affect the revenues and create additional risks for the Corporation. These terms include, possibly among others, the following:

- The Corporation and its partners are required to complete certain minimum work programs during the three or four year phases of the terms of the PSCs. In the event the venture participants fail to fulfill any of these minimum work programs, the Corporation and its partners must pay to the Government of India their proportionate share of the amount that would be required to complete the minimum work program. Accordingly, the Corporation could be called upon to pay its proportionate share of the estimated costs of any incomplete work programs.

- Until such time as the Government of India attains self sufficiency in the production of crude oil and condensate and is able to meet its national demand, the Corporation and its partners are required to sell in the Indian domestic market their entitlement under the PSCs to crude oil and condensate produced from the exploration blocks. In addition, the Indian domestic market has the first call on natural gas produced from the exploration blocks and the discovery and production of natural gas must be made in the context of the government's policy of utilization of natural gas and take into account the objectives of the government to develop its resources in the most efficient manner and promote conservation measures. Accordingly, this provision could interfere with our ability to realize the maximum price for our share of production of hydrocarbons.

- The Corporation, which is not an Indian company, is required to negotiate technical assistance agreements with the Government of India or its nominee whereby such foreign company can render technical assistance and make available commercially available technical information of a proprietary nature for use in India by the government or its nominee, subject, among other things, to confidentiality restrictions. Although not intended, this could increase the Corporation's cost of operations.

- The Corporation and its partners are required to give preference, including the use of tender procedures, to the purchase and use of goods manufactured, produced or supplied in India provided that such goods are available on equal or better terms than imported goods, and to employ Indian subcontractors having the required skills insofar as their services are available on comparable standards and at competitive prices and terms. Although not intended, this could increase the Corporation's cost of operations.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Audit Committee Information-Conflicts of Interest".

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of security holders that involved the election of directors. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Bengal Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and,

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and,

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED as of this 12 day of July, 2011.

(signed) "*Chayan Chakrabarty*"
Chayan Chakrabarty
President and Chief Executive Officer

(signed) "*Bryan C. Goudie*"
Bryan C. Goudie
Chief Financial Officer

(signed) "*Peter Gaffney*"
Peter Gaffney
Chairman

(signed) "*Richard Edgar*"
Richard Edgar
Director

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

Report on Reserves Data

To the Board of Directors of Bengal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's Reserves Data as at March 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2011, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended March 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

			Net Present Value of Future Net Revenue (before income tax, 10% discount rate – CAN$)			
Independent Qualified Reserves Evaluator	**Description & Preparation Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
DeGolyer and MacNaughton Canada Limited	Appraisal Report as of March 31, 2011 on Certain Properties owned by Bengal Energy Ltd. in Canada and Australia dated May 17, 2011	Canada	-	2,298	-	2,298
		Australia	-	10,828	-	10,828
		Total	-	13,126	-	13,126

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated May 17, 2011

DEGOLYER and MACNAUGHTON
CANADA LIMITED

(signed) *"Colin Outtrim"*
Colin P. Outtrim, P. Eng.
President

SCHEDULE "C"
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bengal Energy Ltd. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information. The primary objectives of the Committee are as follows:

1. To assist directors on meeting their responsibilities in respect of the review and approval of the financial statements of the Corporation and related documentation;

2. To provide a communication link between independent directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of the Corporation, none of whom are members of management of the Corporation and all of whom "independent" (as such term is used in National Instrument 52-110 — Audit Committees ("**NI 52-110**") unless the Board shall have determined that the exemption contained in NI 52-110 is available and has determined to rely thereon.

2. The Board shall appoint the Committee Chair, who shall be an independent director.

3. All of the members of the Committee shall be "financially literate" (as defined in NI 52-110) unless the Board shall determine that an exemption under NI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

1. The Committee shall provide oversight on the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. The Committee shall satisfy itself on behalf of the Board with respect to the Corporation's Internal Control Systems and its ability to:

   - identify, monitor and mitigate business risks; and

   - ensure compliance with legal, ethical and regulatory requirements.

3. The primary responsibility of the Committee is to review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   - reviewing accounting treatment of unusual or non-recurring transactions;

   - reviewing disclosure requirements for commitments and contingencies;

   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   - reviewing unresolved differences between management and the external auditors; and

   - obtaining explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, MD&A, annual information forms and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information.

5. With respect to the appointment of external auditors by the Board, the Committee shall:

   - recommend to the Board the external auditors to be nominated;

   - recommend to the Board the terms of engagement of the external auditor,

   - including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

7. The Committee shall review risk management policies and procedures of the Corporation (e.g. hedging, litigation and insurance).

8. The Committee shall establish a procedure for:

    - the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

9. The Committee shall review and be apprised of any intent of the Corporation regarding the hiring of partners and employees who work on the Corporation's account and former partners and employees of the present and former external auditors of the Corporation.

10. The Committee shall have the authority to investigate any financial activity of the Corporation. All employees of the Corporation are to cooperate as requested by the Committee.

11. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of the Corporation without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every motion shall be decided by a majority of the votes cast. In case of an equality of votes, the Chair of the meeting shall not be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board unless otherwise determined by the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the

Committee consider appropriate. At each of these meetings, the Committee will have an "in-camera" session with the external auditors.

6. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Committee Chair.

Definitions — In these Terms of Reference:

"Financially literate" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

Review of Terms of Reference

The Committee shall review and assess these Terms of Reference periodically as it deems appropriate and recommend changes to the Board.

Approved and adopted by the Board: June 10, 2009