TSX: BNG

BENGAL ENERGY LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

MARCH 31, 2018

June 28, 2018

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bopd	barrels of oil per day	Mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	MM	million
Bbls/d	barrels per day	MMbtu	million British Thermal Units
NGLs	natural gas liquids	Mcfe	thousand feet of gas equivalent

Other

API	American Petroleum Institute
˚API	an indication of the specific gravity of oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and 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
mD	millidarcy
m	metres
m^3	cubic metres
km	kilometres
km^2	square kilometres
MBOE	1,000 barrels of oil equivalent
$M	thousands of dollars

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. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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 the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**ATP**" means Authority to Prospect.

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

"**Bengal International**" or "**BEII**" means Bengal Energy International Inc., a wholly-owned subsidiary of Bengal 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 maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**EPT**" means Extended Production Test.

"**GLJ**" means GLJ Petroleum Consultants Ltd.

"**GLJ Report**" means the report of GLJ dated May 10, 2018 evaluating the oil, natural gas liquids and natural gas reserves of the Corporation as at March 31, 2018.

"**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.

"**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;

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

(E) 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*.

"**PL**" means Production License.

"**PCA**" means Potential Commercial Area.

"**PEL**" means Petroleum Exploration License.

"**PPL**" means Petroleum Production License.

"**PRL**" means Petroleum Retention License.

"**RL**" means Retention License.

"**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, 2018.

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 regulation and related 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 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, including with respect to the frac programs expected on ATP 752 and timing of production on such wells following completion of the frac programs; the expectations surrounding upcoming lease relinquishments; receipt of the grant of additional PCAs over ATP 752; the completion of seismic interpretation; 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 including, without limitation the timing, location and targeted zones of current and future wells; availability of rigs, equipment and other goods and services; the prospectivity of ATP 934; the results of the AVO/Inversion workflow on ATP 934; timing of the EPT; expectations regarding the final approval of the Corporation's exit from India; 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; and timing of acquisitions. In addition, statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the 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 Australia and globally; industry conditions including changes in laws and regulations, including the adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Australia and globally; the level of 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 estimates; the production and growth potential of Bengal's assets; governmental regulation of the oil and natural gas industry; a failure to obtain required approvals of regulatory authorities in 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; results of geological, geophysical and reservoir analysis and testing 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; imprecision of reserve estimates; 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 the section entitled "*Risk Factors*" in this Annual Information Form and 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 Annual Information Form, 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 and extensions; 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; receipt of the grant of additional PCAs over ATP 752; the timing of the EPT; the timing and completion of frac programs expected on ATP 752 and timing of production on such wells following completion of the frac programs; the timing and expectations surrounding upcoming lease relinquishments; the completion of seismic interpretation; 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 Annual Information Form 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 Annual Information Form 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 Annual Information Form 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

Name, Address and Incorporation

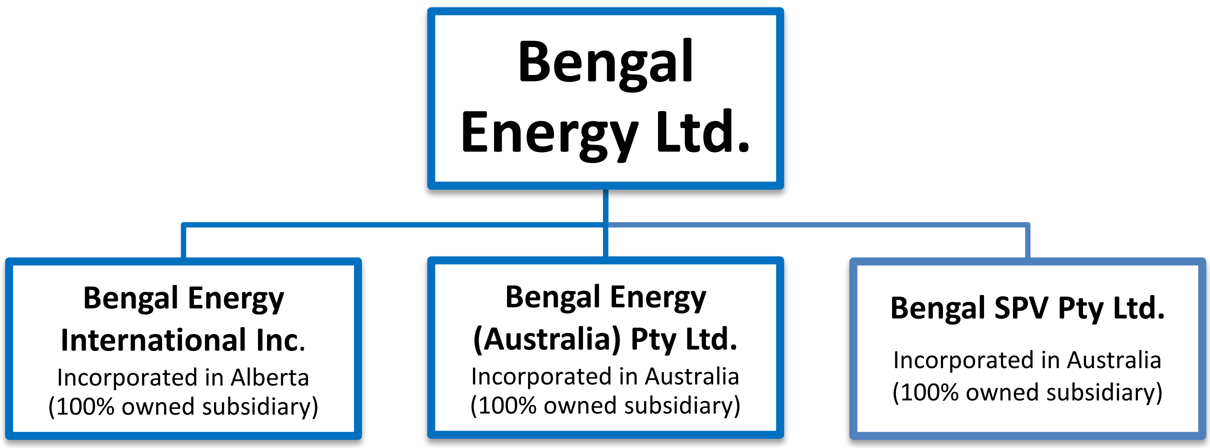
The Corporation was incorporated under the ABCA on May 13, 1996 as "694460 Alberta Inc." On June 18, 1996, the Corporation filed Articles of Amendment to change the Corporation's name to "Briggand Energy Corp.", and on October 8, 1996 to amend its share capital and to remove the private company restrictions 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 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1 and its head and principal office at 2000, 715 – 5th Avenue S.W., Calgary, Alberta T2P 2X6.

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

Intercorporate Relationships

The following chart illustrates the Corporation's corporate structure as at the date hereof:



DESCRIPTION OF THE BUSINESS AND OPERATIONS

General

Bengal is an international junior oil and natural 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 Australia. The Corporation has oil production in the Cooper/Eromanga Basin in Australia and an active inventory of oil and natural gas opportunities in Australia. The Corporation also is currently awaiting final approval to exit India, where it has no active operations.

Corporate Strategy

Bengal has producing and prospective light oil-weighted assets in Australia. Bengal offers exposure to lower risk, current production and cash flow, combined with longer-term high potential impact exploration projects. The Corporation's strategy is to achieve per share growth in cash flow, production and reserves while establishing an attractive portfolio of future drilling and exploration opportunities. 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 to its primary areas of focus. Bengal intends to grow its resource and reserves base within its existing acreage, most of which were acquired through bid rounds in Australia. In addition, Bengal intends to continue building strategic alliances with appropriate local partners and large operators in Bengal's primary areas of focus.

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

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

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

(ii) risked return versus cost of capital;

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

(iv) oil and natural gas production levels;

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

(vi) the potential for additional reservoir development;

(vii) capital expenditure programs;

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

(ix) drilling plans;

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

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

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

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

(xiv) 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 obtain 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 Ended March 31, 2016

ATP 752 Barta Block

In early May 2015, Bengal and its joint venture partners completed the Phase Two drilling campaign on Authority to Prospect 752 ("**ATP 752**") Barta Sub-Block Cuisinier oil field (Bengal's working interest is 30.357%). Average gross production from the Cuisinier field in March 2015, prior to the tie-in of the new Phase Two wells and the reactivation of the Cuisinier-6 well, was approximately 1,653 bopd (502 bopd net to Bengal).

Three of the four cased wells were completed as oil wells. The last well of the Phase Two drilling campaign, Cuisinier-21, tested the northwest flank of the Cuisinier structure. The well encountered oil in the Murta DC70 zone with reservoir pressure at approximately 96% of virgin pressure. The Murta DC70 zone in this well came in structurally below what had been established by other producing wells. Upon perforation the Cuisinier-21 well naturally flowed approximately 380 bopd at 100% oil cut. Bengal expected production rates from the well would increase through installation of mechanical lifting equipment. The well established an oil column of at least 42 metres and further increased the areal extent of the Cuisinier pool. Cuisinier-20, the second of the two development wells in the Phase Two drilling campaign, came in on structure, encountering a well-developed Murta DC70 channel sand that is approximately 14 metres thick.

At the end of 2015, the Cuisinier-1 well had cumulative production of over 192,000 barrels of oil. Cuisinier-20 had been perforated and completed as an oil well. Both the Cuisinier-20 and 21 wells had been flow line connected into Cuisinier facilities. The wells were brought on stream at the end of June 2015 at restricted rates. Production testing of the Cuisinier 21 well in July 2015 indicated a downhole flow restriction that was addressed by an optimization work-over in August 2015. The Corporation and its joint venture partners completed tie-in operations for the two successful Phase Two development wells, Cuisinier-20 and Cuisinier-21 during the third quarter ended December 31, 2015.

The Cuisinier-17 well was cased and perforated and was suspended. The Cuisinier-19 well encountered a thick Murta DC70 sand within the established oil window and was also cased and suspended. Given the volatility of oil prices, Bengal had evaluated various stimulation options for both Cuisinier -17 and 19 prior to committing additional capital. These two remaining appraisal wells (Cuisinier-17 and Cuisinier-19) were evaluated as candidates for stimulation options and the joint venture determined these wells would not be tied in unless commercial flow rates were established post fracture stimulation.

In the third quarter ended December 31, 2015, Bengal and its joint venture parties completed a five well hydraulic stimulation program. Four of the five wells were placed back into production during the fiscal fourth quarter of 2016, demonstrating an aggregate incremental rate of approximately 240 gross bopd or 73 bopd net to Bengal, which represented an increase in post stimulation production as at December 2015 compared to average production prior to the commencement of the program. The aggregate incremental rate of production for all five wells increased to 73 bopd net to Bengal as at December 2015.

ATP 934 Barrolka Permit

Effective April 1, 2015, Bengal acquired an additional 30% working interest located onshore in Australia's Cooper/Eromanga Basin in the State of Queensland Authority to Prospect 934 ("**ATP 934**") from one of its joint venture partners for a total acquisition price of $0.15 million. The acquisition received Ministerial approval in September 2015.

In May 2015, Bengal made an application for special amendment to the Queensland Government for a smaller work program to reflect geographical conditions that may preclude surface access to parts of ATP 934. During the first quarter ended June 30, 2015, Bengal reduced its ownership position in this operated and gas prone permit to 71.43% through the disposition of 8.57% to the remaining original joint venture party. In July 2015, Bengal, as operator, received approval from the Queensland authorities for the requested work commitment revisions on this gas focused application permit.

In September 2015, Bengal was advised by the regulating authority that revisions to its Environmental Authority granted by the Queensland Department of Environment and Heritage Protection relevant to the new Wild Rivers legislation conditions as related to ATP 934 would be forthcoming during the calendar year 2016. The revisions to the Environmental Authority were made and Bengal is currently fully compliant with the updated revisions.

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

On March 1, 2016, the operator of the permit applied to the Government of Tamil Nadu's Commissioner of Geology and Mining for a further 3 year extension of the PEL to March 1, 2019. The block remained under force majeure, subject to stakeholder negotiations, which was further extended on February 3, 2016.

ATP 732 Tookoonooka

Bengal's farm-in partner on the exploration block located onshore in Australia's Cooper/Eromanga Basin in the State of Queensland Authority to Prospect 732 ("**ATP 732**") announced its withdrawal from the farm-in and reassigned their 50% equity back to Bengal on January 27, 2016. The farm-in partner drilled one well (Tangalooma-1) and completed the acquisition of 300 km^2 of 3D seismic. There were no remaining commitments on this permit until after March 2017, at which time a Phase 2 work program was to be considered. Bengal now retains a 100% working interest in this permit.

General

On April 23, 2015, the directors of Northstar Energy Pty Ltd., a then wholly owned subsidiary of the Corporation, resolved to deregister the company and made application with the Australian Securities Investment Commission ("**ASIC**"). The Corporation received formal notification from the ASIC of the company deregistration on June 28, 2015.

On April 10, 2015, Mr. William Wheeler acquired, directly and indirectly, 57,000 Bengal Shares through the TSX in reliance on the normal course purchase exemption set out in Section 4.1 of National Instrument 62-104 – *Take-Over Bids and Issuer Bids*.

Fiscal Year Ended March 31, 2017

ATP 752 Barta Block

During the fourth quarter of 2017, the Corporation completed and tied in the Cuisinier-22, Cuisinier-24, Cuisinier-25 and Shefu-1 wells along with the fracture stimulation program at Barta North 1. All five wells drilled during the year were successful in locating oil-bearing sands and four of these wells were completed and commenced production in May 2017. The fifth well, Cuisinier-23 was suspended as a future fracture stimulation candidate following the evaluation of nearby well performance. This drilling program included one appraisal well ("**Cuisinier-22**") and one exploration well ("**Shefu-1**"). Successful drilling of the appraisal and exploration locations materially increased the Company's reserve volumes by expanding the applicable pool boundaries.

ATP 934 Barrolka Permit

Bengal completed reprocessing and interpretation of 500 line kilometers of 2D seismic over this permit. Seismic amplitude inversion studies were commenced during the year ended March 31, 2017 and the most favorable areas of the permit were high-graded for additional detailed geophysical work to be potentially be undertaken by the Corporation in the future. The Corporation was encouraged by natural gas discoveries near the Barrolka permit during

2017, which suggested the presence of a regional gas resource. Bengal is the operator of this permit and, in the fiscal year ended March 31, 2017, held a 71% working interest.

ATP 732 Tookoonooka

The Corporation applied for the regulatory relinquishment of 1/3 of the block and filed a revised work program covering the period March 2015 through March 2019. During the year, Bengal commenced a study of the Permian gas potential along the northern flank of the permit as well as the largely unexplored oil potential in the southern part of the permit closer to the producing Jackson/Jackson South Field.

ATP 752 Wompi

The Nubba-1 well drilled on the Wompi sub-block of ATP 752 encountered multiple oil shows within the Jurassic, as well as up to 6 metres of Permian Toolachee gas. Pressure testing, as well as logging, suggested that this Toolachee gas well could be part of a gas column that may be up to 70 metres in height. This suggested the prospective gas pay extends down dip of the Nubba-1 well where seismic indicated the Toolachee section thickens. On July 13, 2016, the operator applied to the Department of Natural Resources and Mines of the Queensland Government for a 22,487 acre PCA which will allow for commercialization during the term of the PCA. Any produced natural gas would likely be pipeline connected to the nearest gas transmission line in the area, which is approximately 5 kilometres from the Nubba-1 well. The Wompi sub-block of ATP 752 (38% Bengal interest) offers Bengal moderate risk exploration in a well-established, oil-producing fairway with multi-zone potential and evaluation by the joint venture of the appropriate timing to continue the development of this discovery continues.

RL 84 (formerly PEL 113, Murteree), & Petroleum Production Licence 215, South Australia

On September 28, 2016, the Corporation assigned its 35% working interest in RL 84 and its 32.67% working interest in PPL 215 to the operator, Stuart Petroleum Ltd., for a nominal fee which cannot be disclosed for due to confidentiality obligations. No reserves had been assigned to either tenement in the Corporation's independent reserve assessment and evaluation prepared by GLJ Petroleum Consultants Ltd. with an effective date of March 31, 2016.

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

Effective June 1, 2016, Bengal and its joint venture partners unanimously agreed and provided notice to the applicable Government of India Authorities of its intention to exit the CY-ONN-2005/1 exploration block. The joint venture was unable to acquire the land rights required for exploration causing a force majeure condition for the duration of the first term of exploration, and was therefore entitled to exit the permit without penalty for unfinished work program commitments. This triggered a $7.4 million impairment equivalent to the asset's entire carrying value in the fourth quarter of the fiscal year ended March 31, 2016. In April of fiscal 2017, this application was accepted by the Director General of Hydrocarbons and is currently awaiting final approval from the Ministry of Petroleum and Natural Gas. With the exit from the permit, the Corporation has effectively ceased all operations in India.

General

On August 25, 2016, Bengal negotiated the extension of the term of its secured credit facility ("**Credit Facility**") with Westpac Institutional Bank to December 31, 2018. The Credit Facility had a borrowing base of US 15 million, which was reduced to US 10 million on December 31, 2017 and was to be reduced to US$ 5 million on June 30, 2018 and to nil on December 31, 2018 in the event that it was not further extended.

On December 29, 2016, Bengal completed a fully subscribed rights offering (the "**Rights Offering**") whereby Bengal issued 34,088,898 Common Shares at a subscription price of $0.12 per Common Share for aggregate gross proceeds of $4,090,667.76. Pursuant to the Rights Offering and a standby purchase agreement entered into between Bengal and Texada Capital Management Ltd. (a corporation controlled by Mr. William Wheeler), Mr. Wheeler acquired, directly and indirectly, an additional 13,201,418 Common Shares. The net proceeds from the Rights Offering were allocated to fund Bengal's development program on the Barta Sub-Block of ATP. This included the completion and tie in of Cuisinier-22, Cuisinier-24, Cuisinier-25 and Shefu-1 wells, which occurred in the first quarter of 2017, fracture stimulation of Barta North and Cuisinier-22 wells, which occurred in December 2016 and January 2017 and funding the acquisition of Barta West 3D seismic, which commenced during the third quarter of calendar 2017.

Fiscal Year Ended March 31, 2018

ATP 752 Barta Block

During the fourth quarter of fiscal 2018, the Corporation finalized four wells at Cuisinier to be fracture stimulated. The frac programs are expected to be conducted early in the third calendar quarter of 2018 with results known shortly thereafter. Prior frac programs showed positive results and increased well productivity. The Barta West 3D seismic program processing was completed during the fiscal year ended March 31, 2018 and is in final stages of interpretation.

ATP 732 Tookoonooka

On April 28, 2017, the Corporation lodged a Relinquishment Notice nominating the relinquishment of 290 sub-blocks (33.33% of the original size of the tenement or approximately 218,000 acres) pursuant to the mandatory relinquishment requirement for the permit. This nomination was approved by the regulating authority in April 2017. This relinquishment reduced the remaining permit area of ATP 732 to 576 sub-blocks (436, 223 acres) effective March 31, 2017. At the same time Bengal lodged an application for the ATP 732 second term Later Work Program ("**LWP**") for the period March 31, 2015 to March 31, 2019. This application was granted May 30, 2017 and was based on additional geological and geophysical studies of previously acquired technical data. Given this relinquishment program and the fact that, upon review, the Corporation has no intention of developing or renewing such leases that are to be relinquished in March 2019, the carrying value of ATP 732 was written down to $5.38 million for the year ended March 31, 2018.

PCA 155 Nubba/Yilgarn, ATP 752 Wompi Sub Block

A PCA application for the areas surrounding the Nubba-1 well and the previously drilled Yilgarn-1 well was lodged by the operator of this block and PCA 155 Nubba/Yilgarn was subsequently granted by the Queensland Government on April 3, 2017. The PCA has a 15-year term. An EPT of the Nubba-1 well on PCA 155 is planned; however, the operator has not finalized the timing for this work.

ATP 934 Barrolka Permit

On January 23, 2018, the Corporation acquired an additional 28.57% working interest in its operated permit ATP 934. Bengal has now consolidated its ownership of ATP 934 to 100%. The purchase price was AUS$ 311,221 paid in cash and potential future cash payments of up to AUS$ 1,000,000, subject to certain conditions and commercial benchmarks being achieved.

AC/RL10 (formerly AC/P24) Ashmore Cartier Area, Timor Sea, Offshore Australia

Bengal holds a 10% working interest in the offshore Ashmore Cartier Retention License 10 ("**AC/RL 10**") located in the Ashmore Cartier area of the Timor Sea, west of Australia comprised of approximately 168 km^2 (41,514 acres).

This permit was granted as a five-year RL on March 22, 2013, which expired on March 21, 2018. A LWP application was successfully lodged by the operator of the permit and the permit was renewed on January 9, 2018 for a further five years and now expires on March 2, 2023. The operator continues to reprocess existing 3D seismic data and evaluate commercialization options.

Oak, British Columbia, Canada

In August 2017, the Corporation finalized a conveyance agreement with Procyon Energy Corp. ("**Procyon**") where Procyon acquired all of Bengal's interests in the Oak area of British Columbia including all related Petroleum and Natural Gas ("**PNG**") Leases relating to the 5-30-86-17W6 and the 1-30-86-17W6 wells and all facilities associated with the PNG leases and wells. Bengal agreed to quitclaim all of its right, title and interest on the PNG leases, wells and associated facilities and Procyon, for a nominal cost agreed to assume all financial responsibility for abandonment and reclamation obligation costs.

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

The Government of India Authorities advised at the April 25, 2017 Management Committee Meeting that the operator's request to exit for the CY-ONN-2005/1 without payment of cost for any unfinished work program is now formally under consideration. This application is currently awaiting final approval from the Ministry of Petroleum and Natural Gas. With the exit from the permit, the Corporation has effectively ceased all operations in India

Credit Facility

On March 5, 2018, Bengal negotiated an amendment (the "**Amendment**") to the Credit Facility, which included a deferral of principal payments on the Credit Facility, among other minor housekeeping amendments. The Credit Facility continues to have an expiry date of December 31, 2019 and provides a borrowing base of US$ 12.5 million.

Under the Amendment, the June 30, 2018 principal payment of US$ 2.5 million has been deferred and the December 30, 2018 principal payment has been reduced to US$ 1.5 million (from US$ 2.5 million). The Amendment requires Bengal to make a principal payment of US $5 million on June 30, 2019 and a principal payment of US $6 million on December 31, 2019.

A new cash sharing arrangement was included in the Amendment that requires Bengal to prepay an amount that in aggregate equals 50% of free cash received by the Corporation in the preceding six months. The cash sharing calculation and payment will be done quarterly and will be credited to any outstanding loan amount under the Credit Facility. Between March 2018 and April 2019, any amounts posted to the cash sharing arrangement can be withdrawn by Bengal for any necessary corporate purposes so long as the Corporation is in compliance with the terms of the Credit Facility, as amended. After April 30, 2019, if the Credit Facility has not been cancelled or repaid in full, Bengal must prepay such amounts as necessary to ensure that 100% of the free cash over the previous six month period ending on April 30, 2019 has been prepaid. These payments will not be available for withdrawal under the Credit Facility.

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**") has an effective date of March 31, 2018 and a preparation date of May 10, 2018.

Disclosure of Reserves Data

The Corporation engaged GLJ to provide an evaluation of the Corporation's proved, proved plus probable and proved plus probable plus possible reserves as at March 31, 2018. The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. GLJ is an independent reserves evaluator pursuant to National Instrument 51-101 ("**NI 51-101**") and the COGE Handbook. The Reserves Data summarizes the 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 GLJ 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 of the Corporation has reviewed and approved the GLJ 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.

All of the Corporation's reserves are located in Australia. In discussion with GLJ during the preparation of the GLJ Report, the reserves previously attributed to Bengal's Oak, British Columbia and Toparoa, Australia properties were written off during the year ended March 31, 2016, and, as such, no reserves have been assigned to those properties in the GLJ Report for the year ended March 31, 2018.

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 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 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
AS OF MARCH 31, 2018
FORECAST PRICES AND COSTS

CORPORATE TOTAL	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY: TOTAL	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed										
Producing	448	421	–	–	–	–	–	–	448	421
Non-Producing	32	30	–	–	–	–	–	–	32	30
Proved undeveloped	2,103	1,974	–	–	–	–	–	–	2,103	1,974
TOTAL PROVED	2,583	2,425	–	–	–	–	–	–	2,583	2,425
PROBABLE	3,832	3,596	–	–	–	–	–	–	3,832	3,596
TOTAL PROVED PLUS PROBABLE	6,416	6,021	–	–	–	–	–	–	6,416	6,021

Notes:

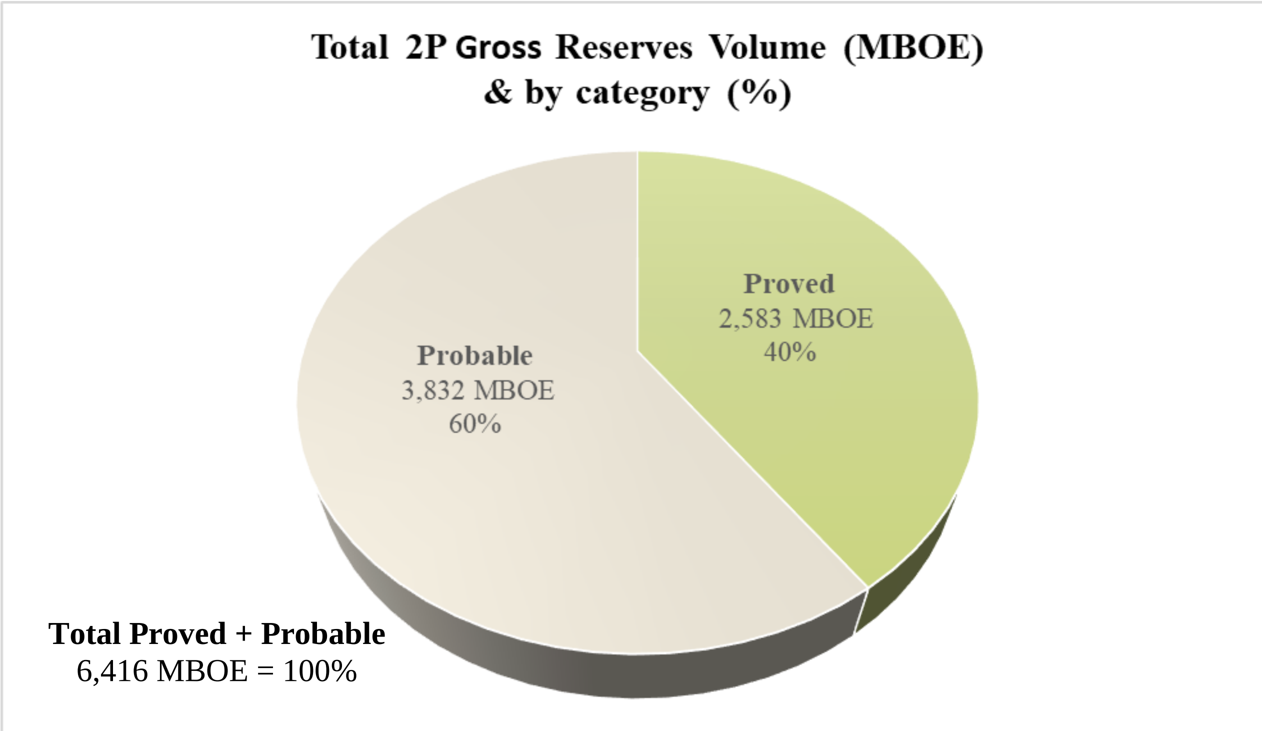
(1) Estimates of reserves of natural gas include associated and non-associated gas.

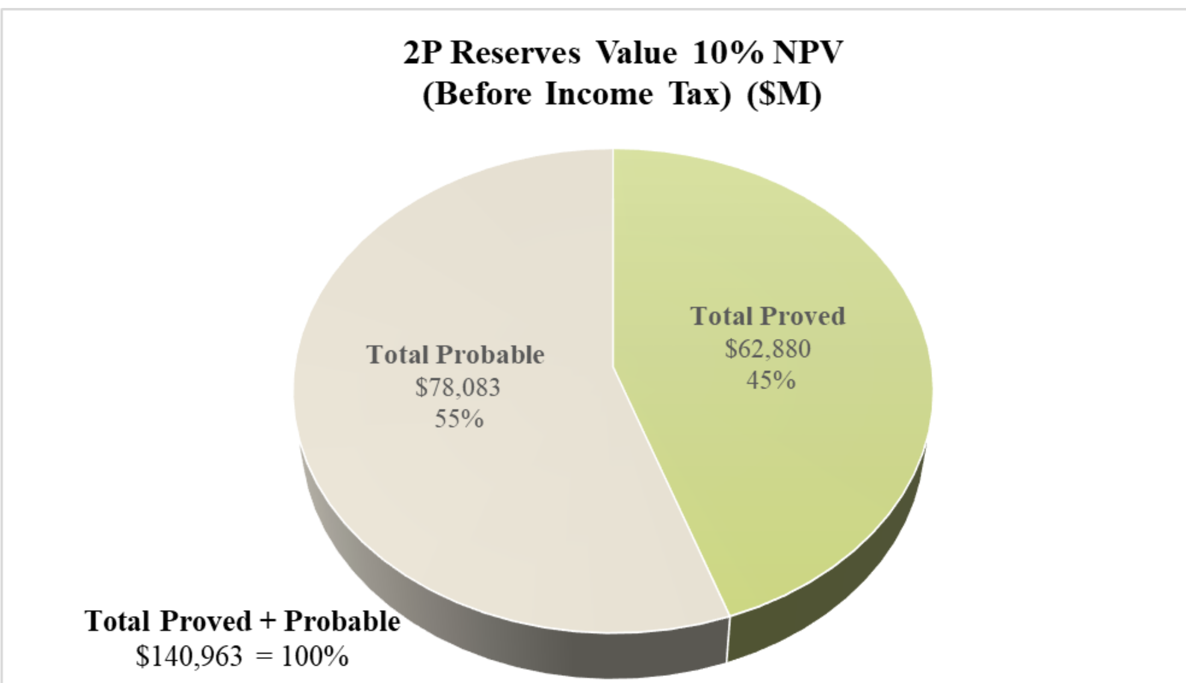
(2) "Gross Reserves" are the Corporation's working interest reserves (operating and non-operating) before the deduction of royalties and without including any royalty interest of the Corporation.

(3) "Net Reserves" are the Corporation's working interest reserves (operating and non-operating) after deductions of royalty obligations plus the Corporation's royalty interests.

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

(5) See definitions for reserve categories in the "Notes Regarding the Reserves Data Tables" below.


Total 2P Gross Reserves Volume (MBOE)
& by category (%)
Proved
2,583 MBOE
40%
Probable
3,832 MBOE
60%
Total Proved + Probable
6,416 MBOE = 100%


2P Reserves Value 10% NPV
(Before Income Tax) ($M)
Total Proved
$62,880
45%
Total Probable
$78,083
55%
Total Proved + Probable
$140,963 = 100%

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF MARCH 31, 2018 FORECAST PRICES AND COSTS

CORPORATE TOTAL	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					Unit Value Before Income Taxes Discounted at 10%/year	Unit Value Before Income Taxes Discounted at 10%/year
($M)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/BOE)	($Mcfe)
PROVED												
Developed Producing	18,751	16,839	15,173	13,793	12,658	18,751	16,839	15,173	13,793	12,658	36.07	6.01
Developed Non-Producing	1,346	1,140	978	851	750	1,346	1,140	978	851	750	32.65	5.44
Undeveloped	90,622	64,178	46,729	34,967	26,815	65,901	47,643	35,261	26,775	20,817	23.67	3.95
TOTAL PROVED	110,719	82,157	62,880	49,611	40,223	85,998	65,622	51,412	41,419	34,225	25.93	4.32
Probable	199,840	121,435	78,083	52,873	37,452	138,701	85,052	55,017	37,495	26,771	21.71	3,62
TOTAL PROVED PLUS PROBABLE	310,558	203,592	140,963	102,484	77,674	224,699	150,674	106,430	78,914	60,997	23.41	3.90

Notes:

(1) Net present value of future net revenue includes all resource income: sale of oil, gas by-product reserves; processing of third party reserves; and other income.
(2) Income taxes includes all resource income, appropriate income tax calculations and prior tax pools.
(3) The unit values are based on working interest reserve volumes before income tax (BFIT).
(4) The numbers in this table may not add exactly due to rounding
(5) See definitions for reserve categories in the "Notes Regarding the Reserves Data Tables" below.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF MARCH 31, 2018 FORECAST PRICES AND COSTS

($M) Reserves Category:	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs[3]	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
TOTAL PROVED RESERVES	256,895	15,783	99,287	25,576	5,530	110,719	24,721	85,998
TOTAL PROVED PLUS PROBABLE RESERVES	678,044	41,731	256,525	58,123	11,107	310,558	85,859	224,699

Notes:

(1) The numbers in this table may not add exactly due to rounding.
(2) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. See "*Additional Information Relating to Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF MARCH 31, 2018

FORECAST PRICES AND COSTS
(Before income taxes and discounted at 10% per year)

Reserve Category	Production Group	($M)	($/BOE)	($/Mcfe)
Proved	Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products)	62,880	25.93	4.32
	Heavy Crude Oil (Including solution gas and associated by-products)	–	–	–
	Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells)	–	–	–
Total Proved		**62,880**	**25.93**	**4.32**
Proved Plus Probable	Light Crude Oil and Medium Crude Oil (Including solution gas and associated by-products)	140,963	23.41	3.90
	Heavy Crude Oil (Including solution gas and associated by-products)	–	–	–
	Conventional Natural Gas (Including associated by-products but excluding solution gas and by-products from oil wells)	–	–	–
Total Proved Plus Probable		**140,963**	**23.41**	**3.90**

Notes:

(1) Unit values are based on the Corporation's net reserves.
(2) The estimated values disclosed do not represent fair market value.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.

Notes Regarding the Reserves Data Tables:

1. Numbers may not add due to rounding.

2. For securities reporting, key economic assumptions will be the prices and costs used in the GLJ Report. The required assumptions may vary by jurisdiction, for example: (a) forecast prices and costs, in Canada under NI 51-101; and (b) constant prices and costs, based on the average of the first day posted prices in each of the 12 months of the reporting issuer's financial year, under U.S. Securities and Exchange Commission rules (this is optional disclosure under NI 51-101).

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

   Reserves estimates have been prepared by GLJ in accordance with standards contained in the COGE Handbook. The following reserves definitions are set out by the Canadian Securities Administrators in NI 51-101 (in Part 2 of the Glossary to NI 51-101) with reference to the COGE Handbook.

   Reserves Categories

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

   - analysis of drilling, geological, geophysical, and engineering data;
   - the use of established technology; and
   - specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

   Proved Reserves

   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.

   Probable Reserves

   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.

   Possible Reserves

   Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

   Other criteria that must also be met for the classification of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status

Each of the reserves categories (proved, probable and possible) may be divided into developed and undeveloped categories.

Developed Reserves

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 nonproducing.

Developed Producing Reserves

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.

Developed Non-producing Reserves

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.

Undeveloped Reserves

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 category (proved, probable and possible) 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.

4. Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves 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 reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 are 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 Section 5 of the COGE Handbook.

5. Forecast Costs and Price Assumptions

GLJ 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, 2018.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (AUSTRALIAN PROPERTIES AS OF MARCH 31, 2018)

	BRENT ($Cdn/Bbl)	Exchange Rate ($US/$Cdn)	BRENT ($US/Bbl)
YEAR FORECAST			
2018 Q2-Q4	87.37	0.7783	68.00
2019	86.08	0.7900	68.00
2020	85.00	0.8000	68.00
2021	85.80	0.8100	69.50
2022	87.20	0.8200	71.50
2023	89.16	0.8300	74.00
2024	92.17	0.8300	76.50
2025	95.18	0.8300	79.00
2026	98.30	0.8300	81.59
2027	100.20	0.8300	83.17
2028+	+2.0%/yr	0.8300	+2.0%/yr

Notes:

(1) 2018 forecast pricing is for last nine months (April 1 - December 31) of 2018.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) Crude oil pricing has been estimated by GLJ as BRENT blend in US dollars. Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.
(5) 2018 forecast pricing is for the last nine months (April 1- December 31) of 2018.
(6) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate. The plant gate price represents the price before raw gathering and processing charges are deducted.
(7) Weighted average historical prices realized by the Corporation for the year ended March 31, 2018 were $81.47/Bbl for light crude oil and medium crude oil.

6. Well abandonment and reclamation costs for wells with reserves or assigned have been included. Additional abandonment costs associated with lease facility abandonment and reclamation expenses have not been included in this analysis. The forecast price and cost assumptions assume the continuance of current laws and regulations. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

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

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

9. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level

tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

(b) Reserves Reconciliation

RECONCILIATION OF CORPORATION GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS

	Light Crude Oil and Medium Crude Oil			Heavy Crude 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, 2017	**2,761**	**4,295**	**7,056**	**-**	**-**	**-**
Extensions(1)	–	–	–	–	–	–
Improved Recovery(1)	–	–	–	–	–	–
Infill drilling(1)	–	–	–	–	–	–
Technical Revisions(2)	(47)	(463)	(509)	–	–	–
Discoveries	–	–	–	–	–	–
Acquisitions(3)	–	–	–	–	–	–
Dispositions(3)	–	–	–	–	–	–
Economic Factors(4)	–	–	–	–	–	–
Production	(131)	–	(131)	-	-	-
March 31, 2018	**2,583**	**3,832**	**6,416**	**-**	**-**	**-**

Notes:

(1) The above change categories correspond to standard set out in the COGE Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as Extensions and Improved recovery.

(2) Includes technical revisions due to reservoir performance, geological and engineering changes.

(3) 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.

(4) Includes economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions and related to price and royalty factor changes.

	Natural Gas Liquids			Conventional Natural Gas			Total BOE		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
March 31, 2017	**–**	**–**	**–**	**–**	**–**	**–**	**2,761**	**4,295**	**7,056**
Extensions[1]	–	–	–	–	–	–	–	–	–
Improved Recovery[1]	–	–	–	–	–	–	–	–	–
Infill drilling[1]	–	–	–	–	–	–	–	–	–
Technical Revisions[2]	–	–	–	–	–	–	(47)	(463)	(509)
Discoveries	–	–	–	–	–	–	–	–	–
Acquisitions[3]	–	–	–	–	–	–	–	–	–
Dispositions[3]	–	–	–	–	–	–	–	–	–
Economic Factors[4]	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	(131)	–	(131)
March 31, 2018	**–**	**–**	**–**	**–**	**–**	**–**	**2,583**	**3,832**	**6,416**

Notes:

(1) The above change categories correspond to standard set out in the COGE Handbook. For reporting under NI 51-101, reserves additions under Infill Drilling, Improved Recovery and Extensions should be combined and reported as Extensions and Improved recovery.
(2) Includes technical revisions due to reservoir performance, geological and engineering changes.
(3) 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.
(4) Includes economic revisions due to changes in economic limits; and working interest changes resulting from the timing of interest reversions and related to price and royalty factor changes.

Additional Information Relating to Reserves Data

(a) 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.

(b) Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of Bengal's three most recent financial years:

	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total Oil Equivalent (MBOE)	
	First Attributed(1)	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
2016	206	1,817	–	–	–	–	–	–	403	1,817
2017	406	2,207	–	–	–	–	–	–	406	2,207
2018(1)	**-**	**2,103**	**–**	**–**	**–**	**–**	**–**	**–**	**-**	**2,103**

Note:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2018.

Proved undeveloped reserves are associated with both undrilled locations and drilled wells that have not yet been logged, or tested as of the effective date of the reserve evaluation. Proved undeveloped reserves partially relate to planned infill drilling locations. The majority of the proved undeveloped locations are scheduled to be on production within a five year time frame.

As of March 31, 2018, Bengal's proved undeveloped reserves represented 81.4% of Bengal's total proved reserves, with proved plus probable ("**P+P**") undeveloped reserves representing 88.8% of its P+P reserves. In light of the timing of Bengal's drilling program relative to its year end reserves evaluation, a portion of these undeveloped reserves will be converted to proved developed through calendar 2018. In addition, given that the focus of Bengal's drilling program was on appraisal and pool delineation rather than development, the reserve evaluation inherently includes greater development potential which is reflected within the report. Further, through an ongoing planned drilling program in Australia over the next 5 years, it is anticipated that a majority of the proved undeveloped reserves will be converted to proved developed, and the majority of probable undeveloped to probable.

(c) 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:

	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total Oil Equivalent (MBOE)	
	First Attributed(1)	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End
2016	649	3,874	–	–	–	–	–	–	649	3,874
2017	201	3,979	–	–	–	–	–	–	201	3,979
2018(1)	**–**	**3,598**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**3,598**

Note:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date March 31, 2018.

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 five 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 and demand, 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. A 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 GLJ Report indicates that Bengal has 3,598 thousand barrels of light crude oil and medium crude oil, no conventional natural gas and no natural gas liquids reserves defined as "probable undeveloped". The change in "probable undeveloped" light crude oil and medium crude oil reserves year over year results from extensions, discoveries, and technical revisions associated with the Murta formation within the Cuisinier property, economic factors and proved production. There are no probable undeveloped conventional natural gas and NGLs reserves as a result of economic factors and no future production.

(d) Significant Factors or Uncertainties Affecting Reserves Data

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 natural 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 the fiscal year ended March 31, 2018 as well as the "*Risk Factors*" and "*Principal Properties*" sections herein.

The Corporation does not anticipate any unusually high abandonment or reclamation costs. Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Bengal's audited financial statements for the year ended March 31, 2018 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

(e) 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:

CORPORATE TOTAL $M	Forecast Prices and Costs	
Year	**Proved**	**Proved Plus Probable**
2018	428	735
2019	2,589	3,704
2020	3,300	3,616
2021	5,386	6,060
2022	6,868	7,554
2023	7,005	7,005
2024	–	7,145
2025	–	7,288
2026	–	7,434
2027	–	7,582
2028	–	–
Thereafter	–	–
Total Undiscounted	**25,576**	**58,123**
Total Discounted @ 10%	**18,153**	**34,762**

Notes:

(1) Future development costs shown are associated with booked reserves in the GLJ 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 $25.6 million will be sufficient to fund the future development costs of its proved reserves disclosed above and $58.1 million will be sufficient to fund the future development costs of the proved plus 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 following is a description of the Corporation's principal oil and natural gas properties as at March 31, 2018, 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, 2018 based on operator statements. The reserve amounts stated are gross reserves, as at March 31, 2018 based on forecast costs and prices as evaluated in the GLJ 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.

The Corporation is engaged in the exploration for, and development and production of, crude oil and natural gas in the Cooper/Eromanga Basin in Australia all of which is on-shore. Bengal has a large acreage position across the onshore Cooper/Eromanga Basin of Australia of approximately 1.1 million gross acres. Bengal's Cooper/Eromanga acreage is split among three principal separate blocks of land that are covered by: ATP 752, ATP 732 and ATP 934.

ATP 752, Queensland, Australia

Bengal has multiple interests in ATP 752. ATP 752 is located on the Cooper/Eromanga Basin and is subdivided into the Barta Sub-Block (Bengal 30.357% working interest) and the Wompi Sub-Block (Bengal 38.08% working interest).

The Barta Sub-Block comprises 154,638 gross acres (46,948 net acres) as well as the 15,815 gross acre (4,801 net acre) PL 303, while the Wompi Sub-Block comprises a total of 117,128 gross acres (44,602 net acres). 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.

The ATP 752 properties include 22 gross (6.98 net) producing light oil wells and 0 gross (0 net) producing natural gas wells as well as 5 gross (1.52 net) non-producing light oil wells and 1 gross (0.38) net) non-producing natural gas wells. Average daily production from the properties for the year ended March 31, 2018, was 360 BOE/d and was weighted 100% to light oil and NGLs. As at March 31, 2018, the GLJ Report attributed proved plus probable reserves of 6,416 Mbbls of light oil and NGLs and 0 MMcf of natural gas to the ATP 752 properties.

On January 29, 2018, Bengal and its joint venture partners filed an application seeking the grant of two PCAs over the ATP 752 Barta Sub-Block. A total of 128 sub blocks were applied for which cover the majority of the prospective lands remaining in the tenement. If successful, these PCAs will allow a further 15 years to assess commerciality. No decision on the applications has been made as of the date hereof.

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2016*" and "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*General Development of the Business – Fiscal Year Ended March 31, 2018*" *and* "*Properties with No Attributable Reserves*".

ATP 732 Tookoonooka, Queensland, Australia

Permit ATP 732 is large in size (435,400 acres) and has been tested by only eight exploration wells to date. The permit is surrounded by existing Permian gas fields and Jurassic and Cretaceous oil fields. The block therefore has good oil potential from the shallow sequence and Bengal has also identified large prospective gas in deeper Permian strata on the Permit. 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 natural gas in other parts of the world. They often contain large pronounced structures however the main challenge will be reservoir trap seal and oil charge. This appears to be the case with ATP 732 as well, therefore a risk reduction focus has been adapted. This will result in targeting prospects within deeper, less fractured parts of the section or more distal structures less disturbed by the impact event.

On March 31, 2019, another 290 sub blocks will be relinquished in conformance with the regulatory terms of ATP 732. The remaining sub-blocks (approximately 288) will stay in good standing until March 31, 2023 subject to regulatory acceptance of a proposed third term LWP.

ATP 732 includes no producing wells as at March 31, 2018 and the GLJ Report therefore attributes no reserves to the ATP 732 property**.**

Bengal is the operator of ATP 732 with a working interest of 100%. 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.

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*General Development of the Business – Fiscal Year Ended March 31, 2018*" and "*Properties with No Attributable Reserves*".

ATP 934 Barrolka, Queensland, Australia

Bengal currently holds a 100% working interest in the 361,268 acre ATP 934 block and is the operator. ATP 934 sits in the heart of the Cooper/Eromanga Basin and is surrounded by known gas fields. ATP 934 flanks the east margin of the large Barrolka gas field. Recent activity west of ATP 934 has resulted in some new oil discoveries. Bengal believes that ATP 934 could be prospective for a basin-centered or stratigraphically trapped gas play. To date, five undrilled structural leads have been identified as conventional gas drilling opportunities. In 2017, seismic re-interpretation involving an AVO/Inversion workflow has resulted in a high grading of more prospective reservoir sand trends on the permit.

The ATP 934 property includes no producing oil wells or producing natural gas wells as at March 31, 2018 and the GLJ Report therefore attributes no reserves to the ATP 934 property.

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

For additional details, see "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*" and "*General Development of the Business – Fiscal Year Ended March 31, 2018*".

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, 2018. As at March 31, 2018, the Corporation had an interest in 28 gross (8.58 net) oil and natural gas wells as follows, all such wells are onshore wells.

	Producing Wells				Non-Producing Wells				Total					
	Oil Wells		Gas Wells		Oil Wells		Gas Wells		Oil Wells		Gas Wells		**TOTAL**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	**Gross**	**Net**
Total	**22**	**6.68**	**–**	**–**	**5**	**1.52**	**1**	**0.38**	**27**	**8.20**	**1**	**0.38**	**28**	**8.58**
Australia	22	6.68	–	–	5	1.52	1	0.38	27	8.20	1	0.38	28	8.58

Notes:

(1) This table does not include dry wells, abandoned wells or wells which have never produced.
(2) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Of the non-producing wells, that the Corporation held a working interest in during the fiscal year ended March 31, 2018, 6 gross (1.90 net) wells were capable of production and had reserves assigned to them. No wells were drilled during the fiscal year ended March 31, 2018. As of the date of this Annual Information Form, none of these wells have been placed on production. Bengal's Oak, British Columbia and Toparoa, Australia properties were written off during the year ended March 31, 2016, and, as such, no reserves have been assigned to those properties in the GLJ Report for the year ended March 31, 2018. Additionally, Bengal does not expect to undertake any further exploration or drilling activities in Canada and has effectively ceased all operations in India and is awaiting final approval from the Ministry of Petroleum and Natural Gas to complete its exit from India.

Properties with No Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at March 31, 2018

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Total	**15,815**	**4,801**	**1,148,990**	**905,230**	**1,164,805**	**910,032**
Australia(2)	15,815	4,801	1,148,990	905,230	1,164,805	910,032

Notes:

(1) Bengal calculates both its gross and net acres on a per lease basis.
(2) Developed acres gross and net do not include PLs under application as at March 31, 2018.

For a summary of the Corporation's work commitments in Australia, see the descriptions under the headings "*Other Oil and Gas Information – Principal Properties*" above, as well as "*General Development of The Business – Fiscal*

Year Ended March 31, 2017", "*General Development of The Business – Fiscal Year Ended March 31, 2018*", above and "*Exploration and Development Activities – Australia*", below.

The Corporation expects that, under mandatory relinquishment terms of the State of Queensland, the rights to explore on approximately a further 252,800 (net 86,000) acres, representing the balance of ATP 752, excluding PL 303 will be relinquished on July 31, 2018. The Corporation has made application for a new PPL, PL 1028, to allow for production of the Cuisinier-19 well which was approved by the regulator on June 4, 2018. The Corporation has also applied for PCA 206 and PCA 207 for 15 years covering the majority of the original land area held under the original Barta Sub-Block. The Corporation has also applied for PCA 155 for 15 years covering the Nubba project on the Wompi Sub-Block. The Barta Sub-Block areas, if the applications are granted, will continue beyond July 31, 2018. No decision has been received from the regulator on the PCA 206 or PCA 207 applications as at the date of this Annual Information Form. The current regulatory workflow backup does not allow for the Corporation to provide an accurate estimate of a decision date for these PCAs. If PCAs 206 and 207 are approved, then a total of 93,403 acres will be relinquished from the Barta Sub-Block effective July 31, 2018, exclusive of PL 303 and PCAs 206 and 207 which will be unaffected, and a total of 56,107 acres will be relinquished on the Wompi Sub-Block on the same date, exclusive of PCA 155 which will be unaffected.

Additionally, for ATP 732, the Corporation made application to relinquish 290 sub blocks equal to approximately 218,000 (net 218,000) acres on March 31, 2017 and received regulatory approval for the relinquishment on May 28, 2017. On March 31, 2019, a further one third of the original tenement area of ATP 732 will be surrendered.

See "*General Development of The Business – Fiscal Year Ended March 31, 2018*" and "*Other Oil and Gas Information – Principal Properties*" above.

Significant Factors or Uncertainties Relevant to Properties with No Attributable Reserves

For further information relative to economic factors and economic uncertainties that may affect the Bengal properties with no attributable reserves please refer to the "*Risk Factors*" section of this annual information form.

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.

Bengal has entered into financial commodity contracts as part of its risk management program to manage commodity price fluctuations related to its primary producing assets being the Cuisinier field in Australia's Cooper Basin.

The Corporation has managed the price application to production volumes through the following contracts:

Time Period	Type of Contract	Quantity Contracted (bbls)	Price Floor (US$/bbl)	Price Ceiling (US$/bbl)
April 1, 2018 – December 31, 2018	Oil - Swap	34,572	47.00	47.00
April 1, 2018 – December 31, 2018	Oil – Put option	30,689	47.00	–
January 1, 2019 – March 31, 2019	Oil - Swap	7,953	55.40	55.40
January 1, 2019 – March 31, 2019	Oil – Put option	7,953	55.40	–

The fair value of the financial contracts outstanding as at March 31, 2018 is an estimated asset of $1.0 million. The fair value of these contracts is based on an approximation of the amounts that would have been paid or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2018 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2019 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended March 31, 2018:

CAPITAL EXPENDITURES	Canada (M$)	Australia (M$)	Total (M$)
Property Acquisition costs – Proven	–	–	–
Property Acquisition costs – Unproven	–	–	–
Exploration:			
Geological and Geophysical(2)	74	1,689	1,763
Drilling	–	4	4
Completions/facilities	–	–	–
Acquisitions	510		510
Exploration Subtotal	584	1,693	2,277
Development:			
Geological and Geophysical	–	373	373
Drilling	–	(54)	(54)
Completions	–	915	915
Acquisitions	–	–	–
Development Subtotal	–	1,234	1,234
TOTAL EXPENDITURES	**584**	**2,927**	**3,511**

Notes:

(1) The numbers in this table may not add due to rounding.
(2) The capital expenditure in Canada, under geological and geophysical are related to Bengal's wholly owned subsidiary, Bengal SPV Pty Ltd., expenditures and to joint venture studies on a non-principal Australian offshore property that the Corporation holds a 10% working interest in. No reserves are attributed to this offshore property as of the year ended March 31, 2018.

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, 2018. No wells were drilled during the fiscal year ended March 31, 2018.

	Exploratory Wells		**Development Wells**	
	Gross	Net	Gross	Net
TOTAL	–	–	–	–
Light Crude Oil and Medium Crude Oil	–	–	–	–
Heavy Crude Oil	–	–	–	–
Conventional Natural Gas	–	–	–	–
Dry	–	–	–	–
Service/Other	–	–	–	–
Stratigraphic Test	–	–	–	–

See "*General Development of the Business – Fiscal Year Ended March 31, 2018*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*" and below for details regarding the drilling program.

Australia

See "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*General Development of the Business – Fiscal Year Ended March 31, 2018*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*" for a detailed summary of activities on Bengal's Australian properties.

ATP 752 Barta, Queensland, Australia

In the fiscal year ended March 31, 2017, the Corporation and its joint venture partners completed the Cuisinier 2016 five well drilling campaign on ATP 752 Barta Block Cuisinier area. The 2016 drilling campaign consisted of five wells commenced on July 21, 2016 and all five wells were cased as potential Murta oil wells. One of these wells was a successful exploration well and four were successful development wells. Completion of four of these five wells commenced in December 2016.

Four of the five wells drilled during fiscal 2017 were connected in May 2017 with initial combined production rates of approximately 245 bopd (gross). These initial rates are less than pre-connection expectations, and continued optimization and well cleanup work is ongoing. With recent positive results from fracture stimulation programs, Bengal and its joint venture partners have reviewed the 2016 wells for stimulation in addition to planning fracture programs to occur immediately after completion in future drilling campaigns. There are current plans to fracture stimulate two of the four 2016 wells, Cuisinier-24 and Shefu-1, during the second quarter of fiscal year 2019.

See "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*" "*General Development of the Business – Fiscal Year Ended March 31, 2018*" and "*Statement of Reserves Data – Other Oil and Gas Information – Principal Properties*".

Tookoonooka - ATP 732

A technical review and high grading of the current prospect inventory has continued with some priority areas identified for further technical work. A LWP for the tenement of $100,000 was approved by the regulator and said work program is now complete. There are currently no outstanding commitments on this permit.

See "*General Development of the Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*General Development of the Business – Fiscal Year Ended March 31, 2018*" *and* "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

ATP 934 Barrolka Permit

In 2016, Bengal completed the geological and geophysical interpretation of the permit with a total of five prospect areas identified. In 2017, additional in-depth technical work on existing 2D seismic, was concluded. This work involved an AVO/Inversion workflow, which has identified trends that exhibit better Permian reservoir sand development. This work has helped high-grade areas for potential 3D seismic acquisition and it is now deemed to be integral to the de-risking process during a future drill location selection process.

See "*General Development of The Business – Fiscal Year Ended March 31, 2016*", "*General Development of the Business – Fiscal Year Ended March 31, 2017*", "*General Development of the Business – Fiscal Year Ended March 31, 2018*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties – ATP 934 Barrolka Permit*".

ATP 752 Wompi

The application for, and approval of, the PCA 155 over Nubba and Yilgarn was granted April 3, 2017. No work was performed on this permit by the Corporation during the fiscal year ended March 31, 2018. The results of an EPT of the planned Nubba-1 well and subsequent reserves confirmation would have implications on any required appraisal on the newly granted PCA 155 and whether the reserves from this well could justify commercialization on a standalone basis. The timing of the EPT is to be determined by the operator. The approved LWP for the first 5 years on the Wompi Sub-Block permit includes geological and geophysical work and the EPT of the Nubba well therefore the EPT must be conducted prior to March 31, 2022.

See "*General Development of The Business – Fiscal Year Ended March 31, 2017*", "*General Development of The Business – Fiscal Year Ended March 31, 2018*" and "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following tables disclose, by product type, the total volume of the Corporation's gross production estimated by GLJ for the fiscal year ended March 31, 2019:

From Gross Proved Reserves:	Light Crude Oil and Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)	%
Total	**322**	**–**	**–**	**–**	**322**	**100**
From Gross Proved plus Probable Reserves						
Total	**379**	**–**	**–**	**–**	**379**	**100**

Note:

(1) The numbers in this table may not add 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			
	2018	**2017**		
	31-Mar	**31-Dec**	**30-Sep**	**30-Jun**
AVERAGE DAILY PRODUCTION[(1)]				
Light Crude Oil and Medium Crude Oil (Bbls/d)	334	354	383	369
Natural Gas Liquids (Bbls/d)	–	–	–	–
Conventional Natural Gas (Mcf/d)	–	–	–	–
Total (BOE/d)	**334**	**354**	**383**	**369**
AVERAGE PRICE RECEIVED (NET OF TRANSPORTATION)				
Light Crude Oil and Medium Crude Oil ($/Bbls)	92.61	98.52	68.40	68.68
Natural Gas Liquids ($/Bbls)	–	–	–	–
Conventional Natural Gas ($/Mcf)	–	–	–	–
Total ($/BOE)	92.61	98.52	68.40	68.68
ROYALTIES PAID				
Light Crude Oil and Medium Crude Oil ($/Bbls)	4.53	6.84	4.09	4.14
Natural Gas Liquids ($/Bbls)	–	–	–	–
Conventional Natural Gas ($/Mcf)	–	–	–	–
Total ($/BOE)	4.53	6.84	4.09	4.14
PRODUCTION COSTS				
Light Crude Oil and Medium Crude Oil ($/Bbls)	35.84	22.49	35.14	19.96
Natural Gas Liquids ($/BOE)	–	–	–	–
Conventional Natural Gas ($/BOE)	–	–	–	–
Total ($/BOE)	35.84	22.49	35.14	19.96
NETBACK RECEIVED[(2)(3)]				
Light Crude Oil and Medium Crude Oil ($/Bbls)	42.66	63.12	27.21	78.02
Natural Gas Liquids ($/BOE)	–	–	–	–
Conventional Natural Gas ($/BOE)	–	–	–	–
Total ($/BOE)	42.66	63.12	27.21	78.02

Notes:

(1) Conventional natural gas volumes are non-associated sales gas volumes.
(2) The totals shown above may not match the corporate totals due to rounding.
(3) Netback per BOE is calculated by dividing revenue (including realized gain/loss on financial instruments) less royalties, operating and transportation costs by the total production of Bengal measured in BOE.

The following table indicates Bengal's average daily production from its important fields, and in total, for the year-ended March 31, 2018**:**

	Light Crude Oil and Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Total	360	–	–	–	**360**
Australian Properties: Cuisinier	360	–	–	–	360

Note:

(1) Numbers may not add due to rounding.

The Corporation's production for the year ended March 31, 2018 was 100% light quality crude oil (32° API or greater).

For the twelve months ended March 31, 2018, approximately 100% of the Corporation's gross revenue was derived from light crude oil and medium crude oil production, 0% was derived from heavy crude oil production and 0% was derived from conventional 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 any other business considerations that 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 102,266,694 Common Shares 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 currently 4,852,500 options to purchase Common Shares outstanding with an average exercise price of $ 0.20, of which 986,096 options to purchase Common Shares are vested.

The holders of Common Shares are entitled to receive notice of, to attend and vote at any shareholder meetings of the Corporation, 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 of 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
2017			
March	0.17	0.125	880,422
April	0.17	0.13	774,112
May	0.155	0.13	688,822
June	0.145	0.10	1,906,534
July	0.12	0.09	689,321
August	0.12	0.095	753,788
September	0.135	0.09	1,783,957
October	0.14	0.10	2,514,664
November	0.15	0.10	1,616,081
December	0.145	0.075	1,926,531
2018			
January	0.13	0.085	1,702,414
February	0.105	0.09	594,481
March	0.12	0.095	503,360
April	0.18	0.105	1,058,937
May	0.175	0.125	1,101,915.00
June (1 to 27)	0.155	0.12	546,250

Escrowed Securities

As of March 31, 2018, 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 current 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 on November 26, 2010. President of Bengal since February 13, 2008.
Ian J. Towers (2)(3) Calgary, Alberta, Canada	Director (Chairman)	November 24, 2005	Appointed Chief Operating Officer and Vice President Engineering at Acquisition Oil Corporation, a private oil and natural gas company, in March 2018. Prior thereto, independent businessman from April 2015 to March 2018. Prior thereto, President, Chief Executive Officer and a Director of Dolomite Energy Inc. from February 2005 to April 2015.
Peter D. Gaffney(2)(3) Alton, Hampshire, United Kingdom	Director	January 30, 2011	Independent advisor to international oil and natural gas industry. Director of Dominie Enterprises Ltd. from November 2005 to present. Director of Upfolds Ltd., a UK company, from September 2013 to August 2016.

Name and Municipality of Residence	Office Held	Director Since	Principal Occupation During Last Five Years
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). Director of Ensign Energy Services Inc. and Pason Systems Inc.
Brian Moss[2][3] Calgary, Alberta, Canada	Director	January 6, 2012	Appointed President and Chief Executive Officer Crown Point Energy Inc. (formerly Crown Point Ventures Ltd.), a public oil and natural gas company, on November 9, 2016. Prior thereto, Executive Vice President and Chief Operating Officer of Crown Point Energy Corp. from June 2012 to November 2016. Director of Crown Point Energy Inc. from May 2012 to April 2015 and from December 2017 to present.
Robert Steele[1][3] Calgary Alberta, Canada	Director	August 27, 2010	Independent businessman since March 2010. Prior thereto, a member of the board of directors of Raise Production Inc. (formerly Global Energy Services Ltd.) from June 2011 to October 2015. Director of Marquee Energy Ltd. (formerly Skywest Energy Ltd.) from June 2010 to June 2013.
William (Bill) Wheeler[1] Vancouver, British Columbia, Canada	Director	January 6, 2012	Private investor. Director and President of Texada Capital Management Ltd., a private investment company, since September 2011. Co-founder of Leith Wheeler Investment Counsel.
Richard Edgar Calgary, Alberta, Canada	Executive Vice President	N/A	Executive Vice President of Bengal since September 2014. President of Poplar Creek Resources Inc., a public oil and natural gas exploration and development company, since July 2009. Director of Shelton Canada Corporation from December 2009 to present. From June 2012 to June 2014, a director of Passport Energy Ltd.
Matthew Moorman Calgary, Alberta, Canada	Chief Financial Officer	N/A	Chief Financial Officer of Bengal since January 2, 2018. Prior thereto, Chief Financial Officer of Green Life Can Corp. from March 2017 to January 2018. Prior thereto, Chief Financial Officer of Blue Quill Energy Corp. from September 2016 to March 2017, Chief Financial Officer of Tuscany International Drilling Inc. from July 2010 to February 2015 as well as VP Finance and Treasurer for Provident Energy Ltd. from September 2003 to August 2010.
Gordon MacMahon Calgary, Alberta, Canada	Vice President, Exploration	N/A	Vice President, Exploration of Bengal since September 2011.

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 June 28, 2018, the directors and officers of Bengal set forth above, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 37,412,357 Bengal Shares or approximately 36.6% of the issued and outstanding Bengal Shares, and 41,632,357 Bengal Shares or approximately 38.9% of the issued and outstanding Bengal Shares on a fully diluted basis (including the exercise of outstanding options to purchase Bengal Shares).

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 was listed on the TSX Venture Exchange ("**TSXV**"). Shelton Canada Corp. was suspended from trading for failure to file its 2008 annual financial statements within the timeframe allowed. Shelton Canada Corp. subsequently filed its annual financial statements and was relisted in June 2009 and subsequently delisted January 4, 2010. In addition, Mr. Edgar was a director and officer of Poplar Creek Resources Inc. when the company was subject to cease trade orders by the Alberta Securities Commission (the "**ASC**"), British Columbia Securities Commissions and Ontario Securities Commissions on May 9, 2014 for failure to file annual audited financial statements within the time frame allowed.

Mr. Wheeler was a director of Azabache Energy Inc. ("**Azabache**") when the company was subject to a cease trade order by the ASC on November 5, 2010 for failure to file annual audited financial statements within the time frame allowed. Azabache subsequently filed its annual audited financial statements and the order was lifted by the ASC on December 16, 2010.

Dr. Moss was an independent director of Richards Oil & Gas Limited ("**Richards**"), which was listed on the TSXV, when it faced severe liquidity problems in early 2010 as a result the collapse in natural gas prices, causing its senior lender to enforce its security. Richards was issued cease trade orders by the ASC, British Columbia Securities Commission and Ontario Securities Commission on May 7, 2010, May 11, 2010, and May 26, 2010, respectively, for failing to make required annual continuous disclosure filings for the year ended December 31, 2009. Richards was granted protection from its creditors under the *Bankruptcy and Insolvency Act* ("**BIA**") on May 5, 2010. Richards' shares were de-listed from the TSX Venture Exchange on July 9, 2010 for failure to pay corporate sustaining fees. Richards filed a proposal under the BIA on September 24, 2010 naming Alger & Associates Inc. as the trustee, which was accepted by the company's creditors on September 24, 2010 and the Alberta Court of Queen's Bench on October 22, 2010. The cease trade orders by the ASC and Ontario Securities Commission were varied in December 2010 to allow certain trades as part of the proposal. After assisting the company with its successful restructuring process, Dr. Moss, along with the rest of the board of directors of Richards, resigned on December 31, 2010.

Mr. Steele was a director of Gamet Resources Limited ("**Gamet**") when the company filed a Notice of Intention to File a Proposal under the BIA on March 17, 2016. The proposal of Gamet was approved by the Alberta Court of Queen's Bench on September 28, 2016. Mr. Steele resigned as a director of Gamet on August 27, 2016.

Mr. Moorman was the Chief Financial Officer of Tuscany International Drilling Inc. ("**Tuscany**"), which was listed on the TSX. On February 2, 2014, Tuscany announced that it and one of its subsidiaries, Tuscany International Holdings (U.S.A.) Ltd. ("**Tuscany USA**") commenced proceedings under Chapter 11 of the United States Bankruptcy Code ("**U.S. Code**") in the United States Bankruptcy Court for the District of Delaware (the "**Chapter 11**

Proceedings") to implement a restructuring of Tuscany's debt obligations and capital structure through a plan of reorganization under the U.S. Code. Tuscany also announced that it and Tuscany USA intend to commence ancillary proceedings in the Court of Queen's Bench of Alberta under the *Companies' Creditors Arrangement Act* to seek recognition of the Chapter 11 Proceedings and certain related relief. Tuscany's plan of reorganization under Chapter 11 of the U.S. Code was approved on May 19, 2014.

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), William (Bill) Wheeler and Robert Steele. The members of the Audit Committee are all independent (in accordance with National Instrument 52-110 — *Audit Committees*) 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 Ensign Energy Services Inc. (TSX: ESI) and Pason Systems Inc. (TSX: PSI) Mr. Howe graduated from the University of Western Ontario with a Bachelor of Arts (Honours) in Business Administration in 1973.

Mr. Robert Steele

Mr. Steele graduated with a degree in Electrical Engineering from the University of Saskatchewan in 1970. Mr. Steele is a professional engineer and independent businessman. He was a member of the board of directors of Raise Production Inc. (formerly Global Energy Services Ltd.) (TSXV: RPC) from June 2011 to October 2015. From June 2010 to June 2013, he was a Director of Marquee Energy Ltd. (TSXV: MQL) (formerly Skywest Energy Ltd.).

Mr. William (Bill) Wheeler

Mr. Wheeler holds a Chartered Financial Analyst designation and received his Bachelor of Commerce degree from the University of British Columbia in 1970. Mr. Wheeler co-founded Leith Wheeler Investment Counsel in 1982. He also sits on the board of directors and is President of Texada Capital Management Ltd., a private investment company.

Pre-Approval of Policies and Procedures

Pursuant to the requirements of the Audit Committee Mandate and Terms of Reference, 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 March 31, 2018	Financial Year Ending March 31, 2017
Audit Fees(1)	$95,000	$95,000
Audit Related Fees(2)	$-	$-
Tax Fees(3)	$9,000	$9,630
All Other Fees(4)	$-	$-

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporation's consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "All Other Fees" include all other non-audit services including the audit of a company acquired by the Corporation.

CONFLICTS OF INTEREST

The directors or officers of the Corporation may also be directors or officers of other oil and natural 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, 2018, Bengal employed ten (10) full-time employees and two (2) part-time consultants at the head office. The Corporation also uses consulting services from a number of service providers on an as needed basis. 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 Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta T2P 4B9.

Computershare 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.

During the year ended March 31, 2018, 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

Other than as set forth herein, 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 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.

Subsequent to the Rights Offering, which closed on December 29, 2016, Mr. Wheeler currently owns, directly or indirectly, or exercises control or direction over 26,891,489 Common Shares, representing approximately 26.3% of the total issued and outstanding Bengal Shares as at the date of this Annual Information Form See "*General Development of the Business — Fiscal Year Ended March 31, 2017 — General*".

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 GLJ, the Corporation's independent engineering evaluators, 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 GLJ 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 GLJ prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP, Chartered Professional Accountants, are independent with respect to the Corporation within the meaning of the relevant rules of and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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 and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, and foreign countries, such as Australia, all of which investors in the oil and natural gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in Australia.

Pricing and Marketing

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 applied. Markets for oil and condensate exist in Australia and low-sulphur light oil finds a ready domestic and overseas market.

Royalties and Incentives

In Australia, taxes are payable to the Federal Government and royalties are also payable to the government of the State in which production is taking place. The principal federal taxes potentially applicable are Income Tax and the recently introduced "Petroleum Resource Rent Tax" ("**PRRT**"). The general income tax rate applying to corporations is 30% of taxable income where income of the Corporation is subject to the Australian tax regime. Beginning July 1, 2012, PRRT became applicable to all Australian onshore and offshore oil and natural gas projects, including coal seam gas and oil shale projects. PRRT is payable at a rate of 40% of a project's taxable profit which is determined after deducting certain project expenses (including exploration and drilling costs). PRRT payments are deductible for company income tax purposes. Credits also apply for current State royalties paid by a corporation and native title compensation. Due to significant deductions available it is generally anticipated that it would be many years into the life of a project before PRRT becomes payable. Depending on the circumstances, an excise licence and excise duty may apply to exports of oil once a threshold of 30 million barrels is reached and if then exceed 3 million barrels annually. A credit is allowed for the purposes of PRRT.

The current royalty imposed by State governments on oil and natural gas production in Australia is generally 10% of wellhead value. The royalty is based on gross revenue less an allowance for certain operating expenses and capital. The amount on which the 10% royalty is payable is generally the arm's length market price for the petroleum less operating costs that relate directly to treating, processing, refining or transporting petroleum (including wages, accommodation, catering and consumables) and less a depreciation allowance (depending on the specific regulations of the relevant State government

In onshore areas that are effected by native title (which has been recognised since the mid-1990s) additional compensation may be payable to recognized indigenous Australian title holders. This compensation is negotiable and generally varies from project to project. Compensation may be payable as a lump sum, by payments over time or in the form of a royalty. Native title holders do not own petroleum. Compensation payments relate to the impact of activities on traditional Aboriginal rights. Compensation is typically negotiated on a good faith basis at the beginning of a project. The Courts may determine compensation if parties cannot agree or in limited circumstances may determine that a project may not proceed without the consent of native title holders.

In Australia, landholders are also entitled to compensation for the impacts of exploration or drilling activities on their land (for example, impacts on farming or grazing). Landholders do not own petroleum and are not entitled to a royalty on this basis. Compensation may be determined by the Courts if landholders and a petroleum tenement holder are not able to agree.

Land Tenure

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 natural gas companies typically submit applications to the applicable state government 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 native title agreements with Aboriginal surface owners. After a successfully negotiated native title agreement, the Corporation is then formally granted the ATP or exploration permit in Queensland or PEL in South Australia by the State. The permits typically provide the Corporation with at least four (4) years, and in some States, up to a maximum of 12 years to conduct its proposed work program with the opportunity for potential extensions. Recent changes to the Petroleum and Gas Act announced by the Queensland State Government on May 28, 2014 may extend onshore ATP work permits by two years to six years. Generally, each state government will reserve unto itself a royalty when production commences which runs with the life of the relevant Production Licence (see comments above). 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 States a small amount is payable by way of annual fee or rent. Failure to pay may also result in termination.

In most cases ATP's held by the Corporation are granted for a period of twelve years. All phases of the oil and natural gas exploration, development and production activities are regulated in varying degrees by the Australian regulatory authorities. Where the ATP has an initial term of twelve years, this period may be 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. Following such relinquishment the next four year period commences and at the end of the last period remaining land must be relinquished. Alternatively, the conditions of an ATP may require relinquishment of 8.33% of area per year over a 12 year period. Generally 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 Licences' which are exempt from relinquishment and stay active until final field abandonment or the end of the specified term of the Production Licence (generally 30 years).

Queensland – PCAs

Another feature of the land tenure system in Queensland is that as an ATP reaches the end of its term, an application can be made to have an area of the ATP declared as a PCA so that the holder can evaluate the potential production and market opportunities for the estimated resource.

The PCA is a way of retaining an area of an ATP beyond its term to provide extra time to commercialise the estimated resource. The maximum term for an ATP is 12 years, while the application for the declaration for the PCA can be for up to 15 years.

A PCA application must include a commercial viability report that shows that the area is likely to be commercially viable within 15 years. The application must also include an evaluation program showing how the holder will overcome any factors inhibiting the commercial viability of the project.

When an area is declared as a PCA, it remains part of the ATP. When the PCA expires, the declared area ceases to be part of the original ATP.

South Australia – PRLs

The PRL scheme is offered by the South Australian Government as a mechanism to recognise the life-cycle for finding, appraising, developing and producing resources. The scheme involves permit operators entering into individual or grouped PRLs to enable greater flexibility for optimising investments and expanding portfolio management options.

PRLs can be sought for covered areas recognised by the Department of State Development ("**DSD**") as lying within known proven productive oil or gas play trends in the Cooper Basin. There is also a provision to include other areas outside of DSD's interpretation of the play, subject to agreement by DSD. A common operator across the covered area is required.

The PRL scheme provides for minimum eligible expenditure targets over the covered areas. DSD has set a minimum expenditure level of $4,500 per km^2 per annum for oil acreage, while the minimum expenditure level within a gas play is on a negotiated bid basis, and is expected to fall somewhere between $7,000 to $9,000 per km^2. In considering these negotiated bids DSD will also take into account the prospectivity of the permit areas and therefore not all permits are expected to fall within the higher target range. Licence areas are currently limited to 100 km^2 so in many cases multiple PRL applications will be required to cover the whole of an original PEL.

Any residual work program yet to be completed under a PEL will need to be carried into the relevant PRLs without variation to timing. This is to preserve the integrity of the work program bidding system for PELs. PRLs are granted for an initial five year period with two five-year extension options, subject to meeting or exceeding the minimum expenditure target

Potential benefits of the scheme include: flexibility of timing of spend over five years; reduced threshold for PRL granting; and security of tenure (potentially up to 15 years).

Regulatory Authorities and Environmental Regulation

In Australia, the Queensland Wild Rivers legislation was enacted to regulate new development and the extraction of natural resources from within a declared wild river and its catchment area. Wild river areas are relatively untouched areas in near natural condition with all or also most all of their natural values intact. To preserve these river systems Wild River Areas have been declared. A wild river declaration means extra protection for the river system. From nomination to potential declaration as a wild river, there is a lengthy process of consultation between the Queensland Government and residents, businesses and interested parties.

The Wild Rivers legislation may compromise the original work program that was bid by Bengal on its ATP 934 as well as drilling operations on parts of the Corporations ATP 732. In this regard Bengal may enter into negotiation with the regulating authority relative to a revised work program and will stay committed to understanding and supporting the Wild Rivers legislation intent and purpose.

During 2014, the Wild Rivers legislation was repealed and replaced with the Regional Planning Interests Regulations. Bengal has previously been advised by the regulating authority its Environmental Authority for ATP 934 had contained a condition that for petroleum activities to be carried out in a wild river area, the activities must comply with the conditions stated for relevant petroleum activities in the wild river declaration for that area. As such, Bengal had been required to comply with relevant conditions from the former Cooper Creek Basin Wild Rivers Declaration. The *Wild Rivers Act 2005* ("**WRA**") was repealed on October 1, 2014 with the commencement of the *State Development, Infrastructure and Planning, (Red Tape Reduction)* and other *Legislation Amendment Act 2014*. The intent of the legislation was to carry forward the environmental protections and land use policy outcomes of the WRA within the new land use planning and development assessment framework of the *Regional Planning Interest Act 2014* (RPI Act). Transitional provisions in sections 715B - D *Environmental Protection Act 1994* ("**EP Act**") (2015 Act No. 4) permitted the following:

(i) Wild River conditions on environmental authorities ("**EAs**") issued before the repeal of the WRA will continue in effect for one year (section 715B EP Act), after which the conditions become unenforceable; and

(ii) EAs issued prior to the repeal of WRA may be amended during the transitional period (October 1, 2014 - September 30, 2015) to replace Wild River conditions with conditions that provide equivalent environmental protection, without agreement or appeal rights of the EAs (section 715B(4) of the EP Act).

As such, a letter was sent to Bengal on June 18, 2015 advising that the WRA was repealed on October 1, 2014 and all existing EAs that referenced wild rivers were required to be amended by September 30, 2015 to achieve equivalent environmental protection.

On September 22, 2015, a decision notice was issued to Bengal with details of all the changes made to the EAs and confirmation that there had been no change in the scope of activities authorized on EPVX01704113 as a result of this amendment.

In effect, the conditions from the Cooper Creek Basin Wild Rivers Declaration (which Bengal was already required to meet), was simply moved onto the Bengal EAs and any references to the former Wild River areas and terms updated and any duplicate conditions deleted. A map was inserted into the EAs to limit the effect of the revised conditions to only within areas which used to be former wild rivers but are now within the strategic environmental area. There was no change in the requirements for the activity, as the amendment of the EAs was limited to include only those conditions that were previously referenced to in the Wild River declaration. This has resulted in an additional number of conditions appearing on the Corporation's EAs; however, there has been no change in the scope of activities authorized.

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.

Further, on February 29, 2014 and January 1, 2015, certain changes to the Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009 (the "**Environment Regulations**") came into effect in Australia. The February 28, 2014 amendments to the Environmental Regulations incorporate changes necessary for the National Offshore Petroleum Safety and Environmental Management Authority ("**NOPSEMA**") to retain the environmental safeguards of the *Environmental Protection and Biodiversity Conservation Act 1999* and provide: (i) clarified environmental assessment and implementation strategy requirements for environment plan submissions; (ii) clarified and strengthened environmental performance and incident reporting requirements; (iii) strengthened duties and responsibilities of the titleholder; and (iv) requirements for 'offshore project proposal' submissions for new large scale development projects in Commonwealth waters. One specific amendment was the change from the "operator" being responsible for compliance with Environment Regulations, to the "titleholder".

The January 1, 2015 changes reflect the Australian Government's response to the June 2010 Report of the Montara Commission of Inquiry, including amendments to the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (the "**OPGGS Act**") to strengthen and clarify the responsibilities of titleholders undertaking petroleum activities.

Amendments to the OPGGS Act became effective on November 29, 2013. The previous requirement to hold insurance was broadened by the amendments to require titleholders to maintain sufficient financial assurance to meet the costs, expenses and liabilities that may arise in connection with carrying out petroleum activities among other things. From January 1, 2015, the Environment Regulations also provide that the NOPSEMA must be reasonably satisfied that a titleholder is compliant with certain provisions of the OPGGS Act prior to accepting an environment plan ("**EP**") or revised EP that was submitted on or after January 1, 2015.

Effective April 27, 2016, the Queensland Parliament significantly broadened the reach of its environmental law by passing the *Environmental Protection (Chain of Responsibility) Amendment Act 2016* (the "**Act**"). The Act was introduced to compel responsible persons connected to corporations in financial distress to meet environmental responsibilities. The Act amends the *Environmental Protection Act 1994* (Qld) to empower the Queensland Department of Environment and Heritage Protection ("**DEHP**") to issue related persons of the Operators with environmental protection orders ("**EPO**") and cost recovery notices.

An EPO may require the related person to: take action to prevent or minimize the risk of environmental harm, rehabilitate or restore land because of environmental harm or give the DEHP a bank guarantee or other form of financial assurance to secure the related person's compliance with the EPO. A failure to comply with an EPO is a criminal offence punishable by a fine. If the non-compliance is willful, a prison sentence may also be imposed. Additionally, breach of an EPO will enable the DEHP to step in and remediate a site, and then recover its rehabilitation costs from the EPO recipient.

The Act also confers power on the DEHP to require the provision of a financial assurance or bond in circumstances where an Operator proposes transferring an environmental authority it holds to another entity and compel persons to answer questions relating to a suspected offence against the new environmental laws.

The Act seeks to maintain accountability for damaging environmental practices. Any person or entity with a connection to a company ("**Operator**") that carries out environmentally relevant activities in Queensland, should consider the risk liability posed by the Act.

Other than the potential effects on ATP 732 and ATP 934 as a result of the repealed Wild Rivers legislation and implementation of the Regional Planning Interests Regulations noted above, Bengal is not aware of any negative or positive effects environmental regulations will have on its activities.

Liability Management Rating Programs

Queensland, Australia

In Queensland, recent amendments to the Environmental Protection Act-1994 have been made. These amendments require any Operating Company with an approved Environmental Authority to lodge a Financial Assurance ("**FA**") deposit either in the form of cash in Australian currency or in the form of a Bank Guarantee. Financial Assurance is based on the likely costs and expenses that the Queensland Government may incur for remediation of surface conditions in the event of default by the Operator. The calculation of the amount of Financial Assurance must be done in accordance with the methodology approved by the Queensland Government. Financial Assurance guarantees remain active until the Operating Company completes remediation. Modifications to the current FA legislation are currently under review.

Climate Change Regulation

Climate change regulation at both the federal and state level in Australia has the potential to significantly affect the regulatory environment of the oil and natural gas industry. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

On July 17, 2014, the carbon tax repeal legislation received the Royal Assent, abolishing the carbon pricing mechanism effective July 1, 2014. As a result, no new carbon tax liabilities will be incurred from July 1, 2014. However, no carbon tax liabilities that were incurred before June 30, 2014 will be removed.

On June 18, 2014, the *Carbon Farming Initiative Amendment Bill 2014* was introduced into Parliament and it received Royal Assent on November 24, 2014. The legislation establishes the Emissions Reduction Fund to replace the carbon tax and provide a transition for the Carbon Farming Initiative by amending the: *Carbon Credits (Carbon Farming Initiative) Act 2011* to: provide for the Clean Energy Regulator to conduct auctions and enter into contracts to purchase emissions reductions; enable a broader range of emissions reduction projects to be approved; and amend the project eligibility criteria and processes for approving projects and crediting carbon credit units; and *Australian National Registry of Emissions Units Act 2011*, *Clean Energy Regulator Act 2011* and *National Greenhouse Energy and Reporting Act 2007* to make consequential amendments. As of December 12, 2014, the Carbon Farming Initiative has been integrated with the Emissions Reduction Fund.

The objective of the Emissions Reduction Fund is to help Australia to meet its emissions reduction target of five percent below 2000 levels by 2020. The Emissions Reduction Fund will build on the Carbon Farming Initiative by offering emissions reduction opportunities to a range of sources beyond the land sector. Through the Emissions Reduction Fund auction arrangements, the Australian Government will purchase Australian carbon credit units ("**ACCUs**") from existing Carbon Farming Initiative projects that are competitive at an auction. This will allow existing participants in the Carbon Farming Initiative to secure a return from eligible projects.

RISK FACTORS

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. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

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, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, 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.

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.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

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

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it properties

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Risks Associated with Foreign Operations

There are significant risks associated with carrying on foreign operations

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes, sudden changes in laws, government control over domestic oil and natural 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 the Corporation's operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal, which can result in the 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.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, processing and storage facilities; operational problems affecting pipelines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and natural gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A 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 because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural 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.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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.

See "*Weakness in the Oil and Natural Gas Industry*".

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition

The exchange rate for the Australian dollar has weakened slightly against the Canadian dollar throughout the year. Bengal, through its subsidiary Bengal Energy (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. The Australian dollar to US dollar exchange rates may have a material impact on operations. The Australian dollar to Canadian dollar exchange rates do not materially impact the Corporation's overall profitability.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

Additionally, an increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and could negatively impact the market price of the Common Shares.

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

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, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Expiration of Licences and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry

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.

Credit Facility Arrangements

Failing to comply with covenants under the Credit Facility could result in restricted access to capital or being required to repay all amounts owing thereunder

Bengal currently has the Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. Bengal is required to comply with covenants under the Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that Bengal does not comply with these covenants, Bengal's access to capital could be restricted or repayment could be required. Events beyond Bengal's control may contribute to the failure of Bengal to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facility, which could result in Bengal being required to repay amounts owing thereunder. The acceleration of Bengal's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility may impose operating and financial restrictions on Bengal that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to Bengal's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Bengal's lender uses Bengal's reserves, commodity prices, applicable discount rate and other factors, to periodically determine Bengal's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce Bengal's borrowing base, reducing the funds available to Bengal under the Credit Facility. This could result in the requirement to repay a portion, or all, of Bengal's indebtedness.

If the Corporation's lender requires repayment of all or portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facility, the lender under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. 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. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. 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 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.

Reserve Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation

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 in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 natural gas;
- royalty rates; and
- 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 and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often 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. 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 natural 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 and 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, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Seismic Data

Seismic data may not be indicative of drilling results

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures, as well as direct eventual hydrocarbon indicators, and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and the Corporation could incur losses as a result of such expenditures. As a result, some of the Corporation's drilling activities may not be successful or economical, and the Corporation's overall drilling success rate or its drilling success rate for activities in a particular area could decline, which could have a material adverse effect on expected results of operations and financial condition of the Corporation.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. 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 Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. 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.

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

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges

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 overruns 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 availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;

- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- 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 be unable to market the oil and natural gas that it produces effectively. Some of Bengal's oil and natural 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.

Infrastructure

The availability of required infrastructure and its development is not certain

Infrastructure development in many of the countries in which the Corporation operates is limited. These factors may affect the Corporation's ability to explore and develop its properties and to store and transport its oil and natural gas production. There can be no assurance that future instability in one or more of the countries in which the Corporation operates, actions by companies doing business there, or actions taken by the international community will not have a material adverse effect on the countries in question and in turn on the Corporation's financial conditions or operations.

Aboriginal Claims

Aboriginal claims may affect the Corporation

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. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

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.

All of Bengal's Native Title Agreements in Australia are in good standing and no native claims have been received or contemplated as of the date hereof.

Dilution

The Corporation may issue additional Common Shares, diluting current shareholders

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

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur 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 oil and natural gas and increase the Corporation's costs, either 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 natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect the Corporation's business, financial condition and the market value of the Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Australia

All phases of the oil and natural gas exploration, development and production activities are regulated in varying degrees by the Australian Federal government and relevant State government, either directly or through one or more governmental entities. The areas of government regulation include matters relating to restrictions on production, income taxes, PRRT, royalties, expropriation of property, environmental protection, land access, rig safety, workplace health and safety and fair employment conditions. 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 relevant government. Generally all future drilling and production programs by the Corporation in Australia must also be approved by or be subject to review by the Australian Federal government and relevant State governments. 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.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and 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. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than 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, process, and reliability of delivery and storage.

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result

The level of activity in the oil and natural gas industry is influenced by seasonal weather patterns. Wet weather may make the ground unstable. Consequently, municipalities and state or territorial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during certain months because the ground surrounding the sites in these areas may consist of swampy terrain. In addition, extreme weather and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation as the demand for natural gas rises during colder winter months and hot summer months. In Australia, the level of activity and production may be influenced by seasonal weather fluctuations such as, but not limited to, flooding. During these flooding and monsoon events it is usual that access roads and oil hauling roads are impacted for periods of time with the resulting down time for oil production activities. In Australia, access to roads and properties may be restricted or prohibited during times of severe flooding. 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 is exposed to credit risk of third party operators or partners of properties in which it has an interest

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 addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. 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 affect 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. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources

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 the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental 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 legislation, no assurance can be given that environmental compliance requirements 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

Loss of key personnel would negatively impact the Corporation's operations

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 personnel 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

Defects in the title to the Corporation's properties may result in a financial loss

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 a defect in the chain of title will not arise to defeat the Corporation's claim. The actual interest of the Corporation in properties may, accordingly, vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation

Bengal'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, property damage, personal injury or other hazards. Although Bengal has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, 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 such uninsured liabilities would reduce the funds available to Bengal. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bengal's financial position, results of operations or prospects.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Geopolitical Risks

Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

Eco-Terrorism Risks

The Corporation's properties may be subject to terrorist attack

The Corporation's oil and natural gas properties, wells and facilities could be the subject of 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 does not have insurance to protect against the risk from terrorism.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and 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 businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so 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 may realize less on disposition than their carrying value on the financial statements of the Corporation.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties

Other companies operate some of the assets in which the Corporation has an interest. 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 depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, 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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the

Corporation form such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows

There can be no assurance that the Australian, Queensland or South Australia state governments or the Canadian federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Climate Change

Compliance with GHG emissions regulations may result in increased operational costs to the Corporation

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the Australian state, territorial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, state, territorial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG 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

Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities

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

Management of Growth

The Corporation may not be able to effectively manage the growth of its business

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 does not pay dividends and there is no assurance that it will do so in the future

The Corporation has not paid any dividends on its outstanding shares. Payment of cash dividends in the future, if any, will be subject to the discretion of the Board of Directors of Bengal and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition, results of operations and prospects. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition. Also see "*Legal Proceedings and Regulatory Actions*".

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of 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 to 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 . See "*Conflicts of Interest*".

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*".

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties

The operations and expertise of the Corporation's management are currently focused primarily on oil and natural gas production, exploration and development in Australia. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being materially adversely affected.

Gathering and Processing Facilities, Pipeline Systems and Trucking

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and tanker truck loading and unloading terminals may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas

Bengal delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by tanker truck. The amount of oil and natural gas that Bengal can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and tanker trucks. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and truck loading and unloading terminals could result in Bengal's inability to realize the full economic potential of its production or in a reduction of the price offered for Bengal's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm Bengal's business and, in turn, Bengal's financial condition, operations and cash flows.

Bengal's oil production is processed through facilities owned by third parties and over which Bengal does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on Bengal's ability to process its production and deliver the same for sale.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar affect on the demand for oil and natural gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Political Uncertainty

The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that impact the oil and natural gas industry, including the balance between economic development and environmental policy. Any actions taken by federal, provincial or municipal governments in Canada may have a further negative impact on the ability to alleviate some of the constraints on the oil and natural gas industry in Canada overall.

Further, in the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign, a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces United States corporate tax rates. This may affect competitiveness of other jurisdictions. It is unclear exactly what other actions the administration in the United States will implement, and if implemented, how these actions may impact the oil and natural gas industry. Any actions taken by the United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, which would impact the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom voted to withdraw from the European Union and the government of the United Kingdom has begun taking steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on oil and natural gas producers' ability to market products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, financial condition, results of operations and cash flows.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the Corporation's reputation in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultant to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Corporation has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Corporation's operations caused by the Corporation's operations could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

Changing investor sentiment towards the oil and gas industry may impact the Corporation's access to, and cost of, capital

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the board of directors, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Intellectual Property Litigation

Unauthorized use of intellectual property may cause the Corporation to engage in or be the subject of litigation

Due to the rapid development of oil and natural gas technology, in the normal course of the Corporation's operations, the Corporation may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or commenced lawsuits against others who the Corporation believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. However, the Corporation may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

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

Report of Management and Directors on Reserves Data and Other Information

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.

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 the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources 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 28th day of June, 2018.

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

(signed) "*Matthew Moorman* "
Matthew Moorman
Chief Financial Officer

(signed) "*Peter Gaffney*"
Peter Gaffney
Chairman of the Reserves Committee

(signed) "*Brian Moss*"
Brian Moss
Director and Reserves Committee Member

SCHEDULE "B"
FORM 51-101F2

REPORT ON RESERVES DATA

BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

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

1. We have evaluated the Corporation's Reserves Data as at March 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at March 31, 2018, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 Corporation evaluated for the year ended March 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – CAN$)			
			Audited ($M)	**Evaluated ($M)**	**Reviewed ($M)**	**Total ($M)**
GLJ Petroleum Consultants Ltd.	March 31, 2018	Australia	-	140,963	-	140,963

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, dated May 10, 2018.

GLJ PETROLEUM CONSULTANTS LTD.

(Originally signed by) "*Patrick Olenick*"

Per: Patrick A. Olenick, P. Eng.
Title: Manager, Engineering

SCHEDULE "C"

AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

I. ROLE AND OBJECTIVE

A. 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:

(a) To assist directors of the Corporation (the "**Directors**") on meeting their responsibilities in respect of the review, approval, preparation and disclosure of the financial statements of the Corporation and related documentation;

(b) To provide a communication link between independent Directors and external auditors;

(c) To enhance the external auditor's independence;

(d) To increase the credibility and objectivity of financial reports; and

(e) To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management and external auditors.

II. MEMBERSHIP OF COMMITTEE

A. The Committee shall be comprised of at least three (3) Directors, 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.

B. The Board shall appoint the Chair of the Committee, who shall be an independent Director.

C. All of the members of the Committee shall be "financially literate" (as such term is defined in NI 52-110 and by the Toronto Stock Exchange or other applicable regulatory authority) 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.

III. MANDATE AND RESPONSIBILITIES OF COMMITTEE

A. 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.

B. The Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

(a) identify, monitor and mitigate business risks;

(b) ensure compliance with legal, ethical and regulatory requirements;

(c) review the Corporation's risk management controls and policies;

(d) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management and the external auditor;

(e) review management steps to implement and maintain appropriate internal control procedures including a review of policies;

(f) review adequacy of security of information, information systems and recovery plans;

(g) monitor compliance with statutory and regulatory obligations;

(h) review the appointment of the Chief Financial Officer; and

(i) review the adequacy of accounting and finance resources.

C. 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:

(a) 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;

(b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

(c) ascertaining compliance with covenants under loan agreements;

(d) reviewing accounting treatment of unusual or non-recurring transactions;

(e) reviewing disclosure requirements for commitments and contingencies;

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

(g) reviewing unresolved differences between management and the external auditors; and

(h) obtaining explanations of significant variances with comparative reporting periods.

D. 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.

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

(a) review and recommend to the Board, for shareholder approval, engagement of the external auditor including, as part of such review and recommendation, an evaluation of the external auditors qualifications, independence and performance;

(b) review and recommend to the Board the annual external audit plan, including but not limited to the following:

(i) engagement letter;

(ii) objectives and scope of the external audit work;

(iii) procedures for quarterly review of financial statements;

(iv) materiality limit;

(v) areas of audit risk;

(vi) staffing;

(vii) timetable; and

(viii) proposed fees;

(c) 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;

(d) 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

(e) 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.

F. Review and advise the Board with respect to the planning, conduct and reporting of the annual audit, including but not limited to:

(a) any difficulties encountered, or restrictions imposed by management during the annual audit;

(b) any significant accounting or financial reporting issue including the resolution of any disagreement between management and the external auditors;

(c) the auditor's evaluation of the Corporation's system of internal controls, procedures and documentation;

(d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weakness; and

(e) assess the performance and consider the annual appointment of external auditors for recommendation to the Board.

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

H. The Committee shall review and receive assurances on the independence of the external auditor.

I. The Committee shall review the non-audit services to be provided by the external auditor's firm and consider the impact on the independence of the external audit.

J. The Committee shall establish a procedure for:

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

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

K. 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.

L. The Committee shall have the authority to communicate directly with the internal auditors of the Corporation (if any) and the external auditors of the Corporation.

M. 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.

N. 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.

O. The Committee shall review material litigation and its impact on financial reporting.

IV. MEETINGS AND ADMINISTRATIVE MATTERS

A. 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.

B. 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.

C. 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.

D. 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.

E. 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.

F. The Corporation's auditors shall be advised of the names of the Committee members and, when appropriate, will receive notice of and be invited to attend meetings of the Committee and to be heard at those meetings on matters relating to the auditor's duties.

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

H. 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.

I. 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.

J. 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.

K. 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. Subject to the foregoing, following their appointment as a member of the Committee each member shall hold office until the Committee is reconstituted.

L. 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.

V. STANDARDS OF LIABILITY

Nothing contained in this Mandate and Terms of Reference is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate and Terms of Reference are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

VI. REVIEW OF MANDATE AND TERMS OF REFERENCE

The Committee shall review and assess this Mandate and Terms of Reference annually and otherwise as it deems appropriate and recommend changes to the Board.

Dated: March 28, 2018