BLACKPEARL RESOURCES INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

February 25, 2010

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GLOSSARY OF TERMS

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* (Alberta);

"**Annual Information Form**" means this Annual Information Form for the year ended December 31, 2009, dated February 25, 2010;

"**BlackCore**" means BlackCore Resources Inc.;

"**BlackPearl**" means BlackPearl Resources Inc.;

"**BlackPearl Shares**" means the common shares in the capital of BlackPearl, as constituted from time to time;

"**Board**" means the board of directors of BlackPearl, as constituted from time to time;

"**CBCA**" means the *Canada Business Corporations Act*;

"**CSS**" means cyclic steam stimulation;

"**EOR**" means enhanced oil recovery methods that use the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen, chemicals or other approved substances for the recovery of petroleum resources;

"**IOGC**" means Indian Oil and Gas Canada;

"**Newmex**" means Newmex Minerals Inc.;

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators and the forms thereunder;

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations* of the Canadian Securities Administrators and the forms thereunder

"**Pearl E&P**" means the company amalgamated under the ABCA through the amalgamation of Nevarro Energy Ltd., Pan-Global Energy Ltd., Atlas Energy Ltd., Cipher Exploration Ltd., Watch Resources Ltd. and Coda Holdings Corp.;

"**SAGD**" means steam assisted gravity drainage;

"**Serrano**" means Serrano Energy Ltd.;

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta;

"**Sproule Report**" means the report prepared by Sproule dated January 15, 2010 evaluating the oil and gas reserves attributable to BlackPearl's properties as at December 31, 2009;

"**TLE**" means Treaty Land Entitlement;

"**TSX**" means the Toronto Stock Exchange; and

"**TXCO**" means The Exploration Company.

ABBREVIATIONS

General

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price)
API	American Petroleum Institute
°API	An indication of the specific gravity of crude oil measured on the API gravity scale
boe	Barrel of oil equivalent of natural gas and crude oil.
boe/d	Barrel of oil equivalent per day
ERCB	Energy Resource Conservation Board
m3	Cubic metres
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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.

Oil and Natural Gas Liquids

bbl	Barrel
bbls	Barrels
bbls/d	barrels of oil per day
Mbbls	thousand barrels
NGLs	natural gas liquids
stb	stock tank barrel

Natural Gas

Bcf	billion cubic feet
GJ	Gigajoule
GJ/d	gigajoule per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMcf	million cubic feet
MMcf/d	million cubic feet per day

CONVERSIONS

To Convert From	To	Multiply By
Acres	Hectares	0.405
bbls	Cubic metres	0.159
Cubic metres	bbls oil	6.290
Cubic metres	Cubic feet	35.494
Feet	Metres	0.305
Hectares	Acres	2.471
Kilometres	Miles	0.621
Mcf	Cubic metres	28.174
Metres	Feet	3.281
Miles	Kilometres	1.609

INTRODUCTORY INFORMATION

Except as otherwise indicated or unless the context otherwise require, the terms "BlackPearl", the "Company", "we", "our" and "us" refer to BlackPearl Resources Inc. and its subsidiaries. Initially capitalized terms used herein and not otherwise defined have the meanings ascribed thereto in the Glossary of Terms.

Unless otherwise indicated, all financial information included and incorporated by reference in this Annual Information Form is determined using Canadian generally accepted accounting principles ("Canadian GAAP").

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all reference to "dollars" or "$" are to Canadian dollars and all references to "US$" are to United States dollars. "$M" refers to thousands of dollars.

FORWARD LOOKING STATEMENTS

Certain statements contained in the Annual Information Form constitute forward-looking statements. These statements relate to future events or to future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should", "predict", "targeting", "seek", "intend", "could", "potential" or similar words. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form. In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- business plans and strategies;
- capital expenditure programs;
- operating expenses;
- the quantity of reserves
- net present values of future net revenues form reserves;
- production levels;
- abandonment and reclamation costs;
- projections of market prices;
- projections of costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes.

The actual results could differ materially from those results anticipated in these forward-looking statements as a result of several risk factors. These factors include, but are not limited to, volatility of oil and natural gas prices, ability to replace reserves, uncertainties associated with estimating oil and gas reserves, substantial capital requirements and the Company's ability to access additional capital, risks and uncertainties inherent in exploration and development activities, government regulation and changes in legislation, environmental matters, aboriginal claims, dependence on key personnel, availability of drilling equipment and skilled personnel, expiration of licenses and leases, competition, conflicts of interest, issuance of debt or equity, title to properties, variations in exchange rates and hedging and uncertainty in global financial markets. Further information regarding these risk factors may be found under the heading "Risk Factors" in this Annual Information Form.

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding future production levels; future oil and gas prices, future operating costs; timing and amount of capital expenditures, the ability to obtain financing on acceptable terms; availability of skilled labour and drilling and related equipment; general economic and financial market conditions; continuation of existing tax and regulatory regimes; and the ability to market oil and natural gas successfully to current and new customers. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

Readers are also cautioned that the foregoing list of factors and risks is not exhaustive. Consequently, there is no representation by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this Annual Information Form are made as of the date hereof, and the Company does not undertake any obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

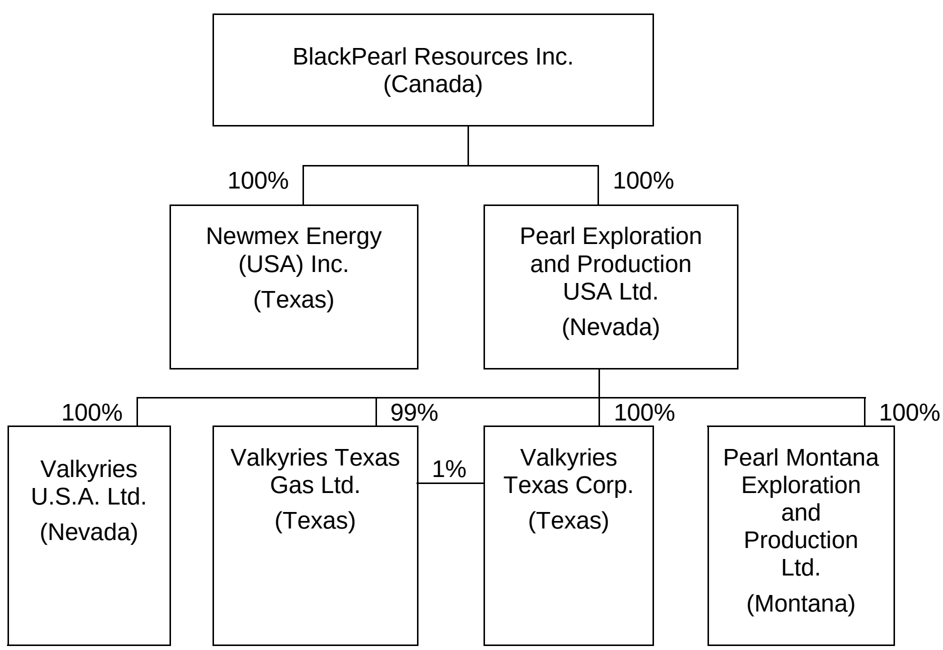
CORPORATE STRUCTURE

BlackPearl is a junior oil and natural gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves located in Canada and the United States. BlackPearl's registered and head office is located at 700, 444 – 7th Avenue S.W., Calgary, Alberta, T2P 0X8.

BlackPearl was incorporated under the ABCA as "Kilo Gold Mines Ltd." on October 15, 1984. On April 22, 1998, Kilo Gold Mines Ltd. filed Articles of Amendment to change its name to Newmex Minerals Inc. On July 22, 2002, Newmex Minerals Inc. continued out of Alberta to Canada under the CBCA. On February 28, 2006, Newmex Minerals Inc. changed its name to Pearl Exploration and Production Ltd. On May 8, 2009, Pearl Exploration and Production Ltd. changed its name to BlackPearl Resources Inc. On January 1, 2010, BlackPearl Resources Inc. was amalgamated with Pearl E&P Canada Ltd., its wholly-owned Canadian subsidiary.

Intercorporate Relationships

The following diagram describes the intercorporate relationships among the Company and each of its subsidiaries, where each principal subsidiary was incorporated or formed, and the percentage of votes attaching to all voting securities of each subsidiary beneficially owned, or controlled or directed, directly or indirectly, by BlackPearl as at January 1, 2010.



GENERAL DEVELOPMENT OF OUR BUSINESS

General

BlackPearl is engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves located in North America and more specifically heavy oil in North America. The majority of BlackPearl's oil and gas interests are located in Canada.

Three Year History

The following describes the development of BlackPearl's business over the last three years.

Year Ended December 31, 2007

On March 1, 2007, the Company acquired all the issued and outstanding shares of Cipher Exploration Inc. ("Cipher"), a privately-held oil and gas company with heavy oil assets in western Canada, for a gross purchase price of $18.6 million, including an amount equal to the aggregate outstanding long and short-term debt of Cipher. At closing, the Company issued 2,047,502 BlackPearl Shares to the Cipher shareholders and assumed $8.3 million of debt. Cipher was amalgamated with Pearl E&P Canada Ltd. on January 1, 2008.

On May 8, 2007, the Company sold its Gulf of Mexico leases to Bayou Bend Petroleum Ltd. ("Bayou Bend") in exchange for ten million shares of Bayou Bend having a value of $2.20 per share for total consideration of $22.0 million. The Bayou Bend shares were subsequently sold in two transactions for cash proceeds of $12.0 million, resulting in a loss on sale of $10.0 million.

On June 20, 2007, the Company commenced trading Swedish depository receipts ("SDRs") on the First North list of the OMX Nordic Exchange. Each SDR represents one issued common share of the Company on deposit with a designated depository and is exchangeable into BlackPearl Shares on a one-for-one basis subject to the payment of an exchange fee.

On July 10, 2007, the Company sold, on a non-brokered, private placement basis, an aggregate of 12 million BlackPearl Shares at a price of $5.05 per share for gross proceeds of $60.6 million. A 4% finder's fee was paid on the gross proceeds of the private placement.

On August 2, 2007, the Company purchased a 24% working interest in the Mooney oil field from Ravenwood Energy Corp. ("Ravenwood"), a private oil and gas company, for $20 million net of standard industry adjustments. The net purchase price paid was $7.5 million in cash and $7.5 million through the issuance of 1,475,108 BlackPearl Shares at a price of $5.12 per share. The remaining $5.0 million in consideration was by way of settlement of certain accounts receivables. The acquisition increased BlackPearl's working interest in the Mooney field to over 98% and added approximately 625 boe/d of production.

On August 23, 2007 the Company acquired a 35% working interest in 2,816 contiguous hectares of oil sands leases (Blackrod) located south of Fort McMurray, in the Athabasca Oil Sands region of northern Alberta. The purchase price was $5.0 million.

On October 17, 2007, the Company sold, on a bought-deal, private placement basis, an aggregate of 29.4 million BlackPearl Shares at a price of $3.75 per share for gross proceeds of $110.3 million. The net proceeds of the private placement were used to fund the acquisition of heavy oil assets in the states of Montana and Utah from PetroHunter Energy Corporation ("PetroHunter"), the Company's ongoing development programs and general working capital purposes.

On October 19, 2007, the Company acquired all of the issued and outstanding shares of Watch Resources Ltd. ("Watch"), a junior oil and gas company with conventional heavy oil interests in north-central Alberta, in an all-share transaction at an exchange ratio of 0.23 BlackPearl Shares for each common share of Watch. At closing, the Company issued 10,542,927 BlackPearl Shares to former Watch shareholders at a price of $4.76 per share. On January 1, 2008 Watch was amalgamated with Pearl E&P Canada Ltd.

On November 6, 2007, the Company closed the agreement with PetroHunter to purchase its heavy oil assets in Montana and Utah. The purchase price will be a maximum of US $30 million, payable as follows: (i) US$7.5 million in cash at closing; (ii) the issuance of the number of BlackPearl Shares equivalent to US$10 million; and (iii) US$12.5 million in cash at such time as either: (A) production from the assets reaches 5,000 bbls/d; or (B) proven reserves from the assets is greater than 50 million barrels of oil.

Year Ended December 31, 2008

On May 22, 2008, the Company closed the sale of certain heavy oil assets to a large integrated energy company. These assets, principally located in the Lloydminster, Celtic, Pikes Peak and Thunderchild areas of Saskatchewan were producing approximately 3,200 boe/d at the time of the sale. In consideration, the Company received $75 million, net of typical purchase price adjustments.

On August 20, 2008 the Company acquired CODA Holdings Inc., a private oil and gas company, whose principal asset was a 30% working interest in 3,886 contiguous hectares of oil sands leases in its Blackrod project, located south of Fort McMurray, in the Athabasca Oil Sands region of northern Alberta. The Company paid $4.5 million in cash and, in 2009, issued 2,500,000 BlackPearl Shares to extinguish $11 million of contingent payments, pursuant to an amendment to the original acquisition agreement. In September and October 2008, the Company acquired an additional 36 sections (9,216 net hectares) of oil sands leases contiguous to the Blackrod project area. In December 2008 the Company entered into an agreement with Serrano to increase BlackPearl's working interest in the original project area from 65% to 80% in return for the disposal of the Company's interests in Serrano and a carried work program of net $5 million over the next twelve months.

On September 4, 2008, BlackPearl Shares commenced trading on the TSX. The BlackPearl Shares were delisted from the TSX Venture Exchange at the close of market on September 3, 2008.

In September 2008, BlackPearl agreed to dispose of its land and tangible interests in the Palo Duro basin to Tyner Resources Ltd. in exchange for an equity interest in Tyner. This transaction was completed on December 30, 2008.

Year Ended December 31, 2009

On January 1, 2009, the Company amalgamated CODA Holdings Inc. (acquired in 2008) with Pearl E&P Canada Ltd., a subsidiary company.

On January 8, 2009, the Company acquired all of the issued and outstanding shares of BlackCore Resources Inc. in exchange for 17,600,000 BlackPearl Shares, as well as 5,000,160 Class A and 5,000,160 Class B share purchase warrants. The principal assets of BlackCore consisted of a 100% interest in the John Lake field in Northern Alberta and $5.5 million cash. Upon the completion of the acquisition, a new management team was appointed consisting of John Festival, President and CEO; Don Cook, Chief Financial Officer; Ed Sobel, Vice President of Exploration; and Chris Hogue, Vice President Operations. Members of the new management team were also the principal shareholders of BlackCore. John Festival and Victor Luhowy were appointed to our Board in connection with the acquisition of BlackCore.

On January 28, 2009, the Company closed an agreement with Serrano to exchange the Company's equity interest in Serrano for an additional 15% interest in the Blackrod area lands (increasing the Company's working interest from 65 to 80% within the main project area) and a carried commitment of $5 million. As a result of the agreements, the Company has become the operator of the Blackrod project.

On April 20, 2009, the Company completed a financing consisting of 52,334,000 special warrants at a price of $0.88 per special warrant representing gross proceeds of approximately $46 million on a bought deal basis. Each special warrant was converted into one BlackPearl Share on May 6, 2009 for no additional consideration.

On May 8, 2009, the articles of the Company were amended to change the Company's name from Pearl Exploration and Production Ltd. to BlackPearl Resources Inc.

DESCRIPTION OF OUR BUSINESS

Description of Properties

The following map outlines the location of our assets as at December 31, 2009.

Core Area Properties – Canada

Onion Lake Heavy Oil Project – Saskatchewan

BlackPearl holds working interests, ranging from 87.5% to 100%, in 41 sections of land located in the Onion Lake area of Saskatchewan. BlackPearl is the operator of the field which is located on the Onion Lake First Nation reserve, along the Saskatchewan/Alberta border near Lloydminster. Approximately 19,200 acres (30 sections) of land overlies a thick accumulation of heavy oil in the Createceous Dina and Cummings sand formation.

During 2009, BlackPearl produced an average of 2,297 boe/d at Onion Lake, primarily heavy oil with an API of approximately 11°.

The Company has identified in excess of 200 additional conventional development drilling locations on the property, twenty-eight of which were drilled in 2009. In addition to conventional drilling, due to reservoir thickness, a portion of the lands at Onion Lake may be amenable to thermal development. In 2009, BlackPearl undertook a two well thermal pilot on the property. The reservoir in this area of the Onion Lake lands is between 15 and 23 metres thick, which makes it suitable for SAGD development. It is expected that the Company will continue primary development of the field for the next 3 or 4 years before SAGD development.

At December 31, 2009, Sproule assigned proved plus probable reserves of 10.1 million barrels of oil and 200 million cubic feet of gas to the Onion Lake area, net to BlackPearl's working interest. No reserves have been assigned for thermal recovery.

Mooney Heavy Oil Project – Alberta

Mooney is a conventional heavy oil property located in north-central Alberta. BlackPearl currently has an average working interest of approximately 98% in 79 sections in the Mooney field. The Mooney field produces mainly from the Bluesky sand formation, at a depth of approximately 900 metres. During 2009, oil and gas production averaged 1,423 boe/d net to BlackPearl. One well was drilled at Mooney in 2009.

BlackPearl has been operating the Mooney property for about five years. The field was initially developed using primary production; however, the Company believes the performance of the Mooney field will be enhanced through Alkali Surfactant Polymer (ASP) flooding. ASP flooding involves adding a polymer chemical to the water to thicken it and additional alkali and surfactant chemicals to mobilize additional reservoir oil. This water and chemical mix is then injected re-pressurizing the reservoir and sweeping additional oil to the producing wells. To date, a three well polymer pilot, operating for about 14 months, has recovered approximately 15% of the oil in place. As a result of the success of the polymer pilot, in late 2009, the Company filed a development application with the ERCB to commence a commercial ASP flood at Mooney. If approved, the first phase of the flood will likely commence in late 2010 or early in 2011. This will initially involve the conversion of producing wells to injectors and installing water and polymer handling facilities. It is expected that it will take 8 to 16 months after initial injection before there will be a production response from the ASP flood. Future phases of the ASP flood will require drilling additional horizontal wells and expansion of the surface facilities.

The Mooney field lies outside the designated Peace River Oil Sands region and is therefore not eligible for oil sands royalty treatment. However, the Alberta government has programs in place that encourage EOR developments by reducing royalties on fields with tertiary recovery programs. An application for royalty relief at Mooney will be submitted in early 2010.

At December 31, 2009, Sproule assigned proved plus probable reserves of 8.7 million barrels of oil equivalent to the Mooney area, net to BlackPearl's working interest.

Blackrod Heavy Oil Project – Alberta

Blackrod is an in-situ (SAGD) oil sands play located south of Fort McMurray, in the Athabasca Oilsands region of Northern Alberta. BlackPearl initially acquired, through Crown land sales, a 35% working interest in the Blackrod lands in 2007. In 2008 and 2009, the Company increased its working interest to 80% as a result of acquiring interests from its partners. BlackPearl is the operator of the project. In addition, the Company has a 100% interest in 31 sections of oil sands leases contiguous to our main Blackrod project area.

The geological formation of interest is the Lower Grand Rapids at a depth of approximately 300 metres.

In 2009, BlackPearl participated in drilling 10 stratigraphic wells on the property to confirm the areal extent and quality of the reservoir. Also in 2009, the Company filed an application with regulatory authorities to undertake a single well pilot SAGD on the property. If approval is granted in 2010, it is expected that steaming could commence during the first half of 2011. In conjunction with filing the pilot application, BlackPearl completed the construction of a 50 mmbtu steam generator that will be used for the pilot and we have completed approximately 23 kilometres (75%) of a 31 kilometre all-weather road into the proposed facility site. The remainder of the road is expected to be completed in the spring.

Blackrod is located in a designated oil sands region and therefore should be eligible for the Alberta oil sands royalty structure. Royalties on the project would be between 1%-9% until the project recovers all costs. After payout of project costs, the royalties would be between 25-40% of net revenues.

There is currently no oil production from the Blackrod area and no reserves have been assigned to this property.

Other Properties – Canada

The Company holds interests and has ongoing operations and production in several other areas of Saskatchewan and Alberta. These include Salt Lake, Ear Lake, Druid, Fishing Lake and Southern Alberta gas area.

Properties - U.S.A.

San Miguel Heavy Oil Project – Maverick Basin, South Texas

BlackPearl, through its wholly owned subsidiary, Newmex Energy (USA) Inc. ("Newmex"), is a 50% participant in a large, shallow depth, heavy oil deposit located in the Maverick Basin in southern Texas. The San Miguel heavy oil project focuses on the San Miguel sandstone which is a large, well defined heavy oil deposit.

During 2008 and early 2009, BlackPearl and TXCO operated a SAGD pilot located within the Chittim "B" Lease. Due to commodity pricing and financial restrictions, the decision was made in February 2009 to suspend operations on the SAGD pilot. Insufficient results were available to make conclusive observations about the success of the SAGD process on these lands.

The Company also participated in two other thermal pilots on the Saner Ranch lease, which included a vertical inverted five spot well pattern and a horizontal three well pattern that both utilized a modified Fracture Assisted Steamflood Technology ("FAST") process. Due to commodity pricing and financial restrictions the decision was made to suspend operations on these pilots. Insufficient results were available to date to make conclusive observations about the success of the FAST process.

There is currently no commercial production in San Miguel and no reserves have been assigned to this property by Sproule. No activities are planned on this property in 2010.

Other Properties – U.S.A.

The Company holds interests in several other areas in the USA, including the West Rozel and Gunnison Wedge in Utah, Promised Land and Fiddler Creek in Montana and Queen City gas fields in Texas. There is limited or no production from these areas and there are only minor evaluation plans contemplated for these lands in 2010.

Heavy Oil Industry

Heavy oil is generally classified as oil with an API gravity of 25° API or less and which can be produced commercially by natural flow. Some heavy oil is highly viscous and it will not flow to a well bore on its own accord in commercial quantities. This highly viscous heavy oil (sometimes referred to as bitumen) is categorized as being either a surface-mineable or an in-situ extractable deposit. With respect to the former process, the oil is recovered through mining and upgraded to synthetic oil. With respect to in-situ deposits, the oil is encouraged to flow to well bores through the application of external energy, such as heat through the use of steam assisted gravity drainage (SAGD) or cyclic steam stimulation (CSS).

Light Oil / Heavy Oil Price Differentials

Processing heavy oil is more expensive than processing conventional light oil and it yields less products compared to refining light oil. Accordingly, producers of heavy oil receive lower wellhead prices for their oil. This difference between prices for heavy oil (API of 25°) and light oil (generally referred to as WTI oil with an API of 40°) is commonly referred to as the "light/heavy price differential".

Volatility in the light/heavy price differential is a result of availability of supply, seasonal demand, pipeline constraints and heavy oil conversion capacity of refineries. See "Risk Factors – Volatility of Oil and Natural Gas Prices and Marketing of Crude Oil and Natural Gas".

Diluent

Heavy oil is usually blended with a lighter hydrocarbon stream referred to as "diluent" to improve its pipeline flow characteristics by reducing the viscosity. The volatility in diluent prices has a significant effect on the wellhead price of heavy oil.

Accessibility to Transport

Canadian heavy oil is dependent on demand from the U.S. Midwest and Rocky Mountain regions. Pipeline constraints to these markets can lead to wide fluctuations in the light/heavy price differential and ultimately the netback received by heavy oil producers. Canadian heavy oil production is not currently pipeline constrained.

Seasonality of Markets

Generally, demand for heavy oil is greater in the summer months due to higher asphalt demand for road construction programs. As a result, the light/heavy price differential will typically narrow in the summer months and widen during the winter, resulting in higher heavy oil prices during those summer periods.

Industry Conditions

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. In western Canada, the various provincial governments have legislation and regulations that govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. Although it is not expected that any of these controls and regulations will affect the operations of BlackPearl in a manner materially different than they would affect other oil and natural gas producers of similar size, the controls and regulations should be considered carefully by investors in the oil and natural gas industry. Outlined below are some of the principal aspects of legislation and regulations governing the oil and natural gas industry. All current legislation is a matter of public record and BlackPearl is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

Pipeline Capacity

As a result of recent pipeline additions and expansions, an excess of natural gas pipeline capacity exists in western Canada, which provides for the ability to deliver all current production to natural gas sales markets.

Currently, there are some concerns with respect to whether the oil pipeline capacity on the inter-provincial pipeline systems is sufficient. There exists the possibility of apportioning pipeline space amongst shippers and this may affect the ability to market oil production.

The North American Free Trade Agreement

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

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur, and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and funds from operations within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to reduce the benefits under such programs or allow such incentive programs to expire without renewal, and consequently we cannot predict whether existing incentive programs will be continued or new incentive programs enacted.

The Canadian federal corporate income tax rate levied on taxable income is 19% effective January 1, 2009 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008, the federal corporate income tax rate will decrease to 15% in three additional steps: 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" containing the Government's proposals for Alberta's new royalty regime, which was incorporated in *Petroleum Royalty Regulation*, *2009* (the "NRF"). The NRF became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production rate, the density of the oil, the vintage of the oil and the selling price of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". In 1992, the Alberta Government introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates these classifications and establishes new royalty rates for conventional oil, natural gas and oil sands. The NRF establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%.

With respect to natural gas, the royalty rates are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of gas produced from wells drilled prior to 1974 and between 15% and 35%, in the case of gas produced from wells drilled after 1974, depending upon a prescribed or corporate average reference price.

The Alberta oil sands royalty payable is based on price-sensitive royalty rates. The royalty payable for pre-payout projects is the gross revenue royalty based on the gross revenue royalty rate. The gross revenue rate starts at 1% and increases for every dollar when oil is priced above $55 per barrel to a maximum of 9% when oil is priced at $120 per barrel or more. The royalty payable for post-payout projects is the greater of the gross revenue royalty based on the gross revenue royalty or the net revenue royalty based on the net revenue royalty rate. The net royalty rate starts at 25% and increases for every dollar when oil is at $55 per barrel to a maximum of 40% when oil is priced at $120 or more.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells at depths between 1,000 and 3,500 metres, which are spudded between November 19, 2008 and December 31, 2013, will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. The election must be made prior to the end of the first calendar month in which the leased substance is produced. All wells using the transitional royalty rates must shift to the rates outlined in the NRF on January 1, 2014.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (i) a five-year oil program for exploration wells over 2,000 metres that are spudded after January 1, 2009 that will provide upfront royalty adjustments in the form of a royalty exemption on either the first $1 million of royalties or the first 12 months of production, whichever comes first; and

(ii) a five year natural gas deep drilling program that applies to wells producing at a true vertical depth greater than 2,500 metres**.** This program will have an escalating royalty credit in line with progressively deeper wells from $625 per metre to a maximum of $3,750 per metre. Any wells spud after December 31, 2013 or any wells that choose the transition option, will not qualify under either program. No royalty adjustments will be granted under either program described above after December 13, 2018. These new programs are to be implemented along with the NRF.

The NRF includes a policy of "shallow rights reversion" which became effective on January 1, 2009 as a result of the *Mines and Minerals (New Royalty Framework) Amendment Act*, *2008*. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas leases issued after January 1, 2009 as well as all existing leases, however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the P&G Tenure Regulation and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas. As of June 25, 2009, the Alberta government has extended these two programs to March 31, 2011. The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of inactive wells.

The Alberta enhanced oil recovery royalty relief program under the Enhanced Recovery of Oil Royalty Reduction Regulation facilitates the use of EOR methods for conservation of petroleum resources. The Program provides for Crown sharing in the incremental costs that are over and above the cost of conventional recovery methods by foregoing royalties on a portion of incremental tertiary production. The program allows deduction of eligible costs which are incremental to the base recovery scheme and approved by the Department of Energy. The major cost categories are: capital, injectants, transportation, consumed energy, breakthrough processing allowance, and overhead allowance.

Royalty reductions are applied only to the Crown's share of incremental production, the volume of which is determined through the application of a constant percentage (T-factor) to the gross production from the scheme. The T-factor is defined as the lesser of either 0.9 or the difference between the recoverable oil reserves estimated for the EOR scheme and the recoverable reserves from the base case scheme, divided by the remaining recoverable reserves for the EOR scheme.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil is determined by a sliding scale based on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") of oil production are different in respect of each of the three crude oil types. The Crown royalty rates and freehold production tax rates are sensitive to the individual productivity of each well and the type of oil produced from the well. Each month, royalty and production tax rates rates are adjusted based on the level of the reference price established by the Province for each type of oil. The base royalty rates vary from 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil". The Crown royalty share of production volume is calculated on each individual well using the applicable royalty rate to the volume of oil produced from the well each month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the oil for the month.

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. For Crown Royalty and freehold production purposes, natural gas is considered either "non-associated gas" or "associated gas". The royalty and production tax classifications of gas production are "fourth tier gas", "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive. The base royalty rates vary from 5% for "fourth tier gas" to 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas". The operator may also elect the Operator Average Gas Price ("OGP") for purposes of valuing the Crown's royalty share of the production volume from each well. The OGP is determined each month by the operator and represents the weighted average fieldgate price ($\$/10^3m^3$) received by the operator for sales of gas during the month. The Crown royalty share is calculated by multiplying the Crown royalty volume determined for each well by the wellhead value of the gas for the month.

Subject to the foregoing description, among other changes, the following were introduced into the royalty and freehold production tax regime as at October 1, 2002.

• A royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (i) oil wells with a finished drilling date on or after October 1, 2002; and (ii) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month.

• A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002. The incentive volumes are applicable to various well types, including:

(a) zero m^3 for non-deep vertical development oil wells and development gas wells;

(b) 4,000 m^3 for non-deep vertical exploratory oil wells;

(c) 6,000 m^3 for non-deep horizontal oil wells;

(d) 8,000 m^3 for deep vertical exploratory oil wells and deep horizontal oil wells; and

(e) 25,000,000 m^3 for exploratory gas wells (no change),

subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

• Elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

In 1975, the Province established the Royalty Tax Rebate ("RTR") as a response to the federal government disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As a consequence of federal government's initiative to reintroduce full deductibility of provincial resource royalties for federal and provincial taxable income purposes. Saskatchewan's RTR will be allowed to wind down commencing January 1, 2007, the carry forward period for any outstanding RTR balances will be limited to seven years.

On June 19, 2007, the Province amended the *Oil and Gas Conservation Act* and the Oil and Gas Conservation Regulations, 1985 to support an Orphan Well and Facility Liability Management Program. The program includes a security deposit system, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the event that a company becomes bankrupt, the security deposit will cover the cost of decommissioning and reclaiming of orphan properties. In addition, the amended regulations introduce the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

The Saskatchewan enhanced oil recovery royalty regime is a cost sensitive system that recognizes the higher investment and operating costs associated with implementing and operating EOR projects. The EOR royalty regime applies to any project that enhances the total recovery of oil through the use of thermal or other techniques and that:

(a) have been approved pursuant to the *Oil and Gas Conservation Act*;

(b) are not waterflood projects; and

(c) are approved by the Minister of the Department of Energy and Resources as an EOR project for the purposes of the applicable regulations.

Two separate royalty rate structures exist, one for projects commencing prior to April 1, 2005 and the other for projects or project expansions commencing on or after April 1, 2005. The EOR royalty rate for projects commencing on or after April 1, 2005 is 1% of gross EOR revenues before investment payout and 20% of net revenue (gross EOR revenue less the total EOR operating costs) after investment payout.

Land Tenure

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

Competition

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

Employees

The Company had 48 full time employees and five consultants as at December 31, 2009. The Company has also entered into arrangements with 22 contract operators to help manage and operate the Company's oil and gas properties.

RISK FACTORS

The Company is exposed to a number of risks inherent in exploring for, developing and producing crude oil and natural gas. The following list describes some of the risks that could have a material impact on the business, operations and financial condition of BlackPearl. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Volatility of Oil and Natural Gas Prices

Historically, the price of crude oil and natural gas has been volatile and is subject to wide fluctuations. These fluctuations are in response to, although not limited to, supply and demand for crude oil and natural gas, market uncertainty, world economic conditions, government regulation, political instability, weather conditions and the prices of alternative forms of energy, all of which are generally beyond the control of the Company. The Company's operations and financial condition are dependent on the prices received for its oil and natural gas production. Any material decline in prices could result in a reduction of BlackPearl's production revenues, net earnings and cash flows. In addition, a decline in prices could affect the value of the Company's reserves, borrowing capacity and the Company's ability to fund future capital expenditures.

Over 80% of the Company's production is from heavy oil. Heavy oil prices are lower than light oil prices due to higher refining costs associated with processing a barrel of heavy oil. This difference between the market price for light oil and heavy oil is commonly referred to as the "light/heavy differential". This differential will fluctuate and, as a result, wider light/heavy differentials may adversely affect the Company's operations.

The Company regularly assesses the carrying value of its assets in accordance with Canadian GAAP. If oil and natural gas prices decline, the carrying value of the Company's assets could be subject to downward revisions, and net earnings could be adversely affected.

Replacement of Reserves

Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. The long-term commercial success of BlackPearl depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves BlackPearl may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in BlackPearl's reserves will depend not only on the Company's ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects.

The Company will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and past practices. No assurance can be given that BlackPearl will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, BlackPearl may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that expenditures made on future exploration by BlackPearl will result in new discoveries of oil or natural gas in commercial quantities or that further commercial quantities of oil and natural gas will be discovered or acquired by BlackPearl. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.

The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited, the Company's ability to make the necessary capital investments to maintain and expand its crude oil and natural gas reserves will be impaired.

Uncertainty of Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors beyond the control of the Company. The reserves and cash flow information set forth herein represent estimates only. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of assumptions and factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable reserves attributable to any group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The Company's actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to its reserves will likely vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Access to Capital

BlackPearl will have to incur substantial capital expenditures in the future in order to carry out its oil and natural gas acquisition, exploration and development activities. There can be no assurance that debt or equity financing or cash generated by operations will be sufficient or available or continue to be available to complete these activities, or on terms acceptable to the Company. The inability of BlackPearl to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

The current worldwide economic downturn has resulted in considerable disruption that has affected the financial and banking system, resulting in a tightening of credit markets, higher costs of borrowing, lower returns on invested cash, and more volatility in the equity markets. These factors could negatively impact the Company in terms of its ability to raise additional capital as well as increased volatility in oil and gas prices which could affect revenues and cash flows and Company valuations.

Operational Risk

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, mechanical or pipe failure, sour gas releases, cratering and oil spills, acts of vandalism, or other unexpected or dangerous conditions, each of which could result in substantial damage to oil and natural gas wells, producing facilities, other property and the environment or in personal injury. BlackPearl has established a comprehensive health and safety program in order to mitigate some of these risks. In addition, the Company mitigates some of these risks by maintaining an insurance program in amounts it considers adequate; however, BlackPearl will not be insured against all of these risks, as well, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and the invasion of water into producing formations.

Government Regulation

The Company's operations are subject to various levels of government regulation. These regulations include matters related to land tenure, drilling, production practices, environmental protection, royalties, marketing and pricing and various taxes and levies. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could have a material adverse impact on the Company's results of operation and financial condition.

The operations of BlackPearl require licenses and permits from various governmental authorities. There can be no assurance that BlackPearl will be able to obtain all necessary licenses and permits that may be required to conduct operations that it may wish to undertake.

Income tax laws or other laws or government incentive programs relating to the oil and gas industry may, in the future, be changed or interpreted differently from the position taken by BlackPearl which may be detrimental to the Company and its shareholders.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial, state and federal legislation. Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of various substances produced or utilized in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be operated, maintained, abandoned and reclaimed after their useful life to the satisfaction of regulatory authorities. Certain of the Company's operations may require the submission and approval of environmental impact assessments or permit applications. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition or results of operations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to government and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the cost of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operation and prospects.

Climate Change

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change ("UFCCC") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other emissions referred to as "greenhouse gases". The Canadian federal government has indicated an intention to regulate emissions of industrial greenhouse gas ("GHG") emissions from a broad range of industrial sectors in the Regulatory Framework for Air Emissions released April 26, 2007 (the "Framework") and updated in a March 10, 2008 document entitled Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, the "Federal Plan"). The Federal Plan outlines proposed policies to reduce GHG emissions intensity of regulated facilities starting January 2, 2010. New facilities will face intensity reduction requirements, beginning in their fourth year of commercial production, of 2% per year from their 'baseline' emissions intensity (e.g. the emissions intensity of their third year of commercial production) until at least 2020.

Targets will be based on a "cleaner fuel standard" (i.e. the use of natural gas as a fuel) for new facilities commencing production before 2012, although new facilities commencing production in 2012 or later that are built "carbon-capture ready" will not need to meet the cleaner fuel standard until 2018. Compliance options under the Federal Plan include: making emissions intensity improvements, making investments in certified carbon capture and storage projects (until 2018), buying offsets or emissions performance credits, and, for a portion of each entity's emissions reduction obligations (the portion would start at 70% and decline to 0% in 2018), making payments of $15/ton until 2012, then $20 or more/ton, to the federal technology fund.

On June 29, 2008, the Canadian federal government launched the first phase of Canada's Credit for Early Action Program, which recognizes Canadian facilities that took a leadership role in reducing emissions of six GHGs between 1992 and 2006 by providing a limited number of emissions credits to those companies and creating a carbon market for the sale of such credits in excess of what is required. On June 10, 2009, the Canadian government announced its offset system for GHGs, which will establish credits that can be traded and will encourage cost-effective domestic GHG reductions in areas that will not be covered by planned federal GHG regulations, such as forestry or agricultural sectors.

The Framework also outlines proposed requirements by the Canadian federal government governing the emission of industrial air pollutants starting in 2010. Proposed compliance mechanisms include fixed emission caps and an emissions credit trading system for certain industrial air pollutants, as well as several options from which companies may choose to meet GHG emission reduction targets. The current status of these proposals is unclear. The Canadian federal government currently imposes reporting obligations under the *Canadian Environmental Protection Act, 1999* for facilities that create GHG emissions.

The Canadian federal government is working with the provinces and territories toward the development of a cap and trade system that will ultimately be aligned with the emerging cap and trade program in the United States. No assurance can be given that either a modified Federal Plan or a North American cap and trade system will or will not be implemented, or what obligations might be imposed under any such system.

In February 2009, the United States and Canada established the Clean Energy Dialogue, to enhance joint collaboration on the development of clean energy science and technologies to reduce GHGs and combat climate change. Three joint working groups have developed an Action Plan of recommendations for joint initiatives in: (i) developing and deploying clean energy technologies, with a focus on carbon capture and storage; (ii) expanding clean energy research and development; and (iii) building a more efficient electricity grid based on clean and renewable generation.

At the July 8 to 10, 2009 G8 Summit in L'Aquila, Italy, Canada and other G8 members recognized the broad scientific view that the increase in global average temperature above pre-industrial levels ought not to exceed two degrees Celsius. The G8 leaders agreed to work together toward the goal of achieving a 50 per cent reduction of global emissions by 2050.

In December 2009, Canada participated in the UNFCCC 15th Session of the Conference of Parties ("COP 15") in Copenhagen, Denmark, the goal of which was to reach a new global agreement for fighting climate change. COP 15 resulted in the Copenhagen Accord, which committed Canada to implement the quantified economy-wide emissions targets for 2020. Canada submitted its targets on January 30, 2010, noting that the emissions reduction target of 17 per cent and base year of 2005 is aligned with the final economy-wide emissions target and base year of the United States, and also noting that its submission was made with the expectation that other parties would also submit emissions targets and mitigation actions in accordance with the Copenhagen Accord.

There has been much public debate with respect to Canada’s ability to meet emission targets and the government’s strategy or alternative strategies with respect to climate change and the control of GHGs. Implementation of strategies for reducing GHGs whether to meet limits required by the Kyoto Protocol, the 2009 G8 Summit, the Copenhagen Accord, or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on BlackPearl and its business, financial condition, results of operations and prospects.

Alberta

Alberta regulates GHG emissions under the *Climate Change and Emissions Management Act*, the *Specified Gas Reporting Regulation* (the "SGRR"), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the "SGER") which imposes GHG emissions limits. Under the SGRR, the Company must report if it has GHG emissions of 100,000 tonnes or more from a facility in any year. Under the SGER, GHG emission limits apply once a facility has direct GHG emissions in a year of 100,000 tonnes or more. Under the SGER, any facility coming into commercial production after 2000 will be considered a new facility and will be required to reduce its emission intensity (e.g. tonnes of GHGs emitted per unit of production) by 2 percent per year beginning in its fourth year of commercial operation, up to an aggregate 12 percent reduction from the emissions intensity level of its third year of commercial operation. The SGER permits the Company to meet the applicable emission limits by making emissions intensity improvements at facilities, offsetting GHG emissions by purchasing offset credits or emission performance credits in the open market, or acquiring 'fund credits' by making payments of $15/per tonne to the Alberta Climate Change and Management Fund. The price of fund credits could be raised, and the required reductions in GHG emissions intensity could be increased to unspecified levels. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

Saskatchewan

On December 1, 2009, the Government of Saskatchewan reintroduced Bill 126, *The Management and Reduction of Greenhouse Gases Act*, to the legislature. The proposed legislation would establish a framework for the province to meet its target of reducing GHGs by 20 per cent from 2006 levels by 2020 and would foster innovation in low-carbon technologies. The legislation would establish the Saskatchewan Technology Fund, which would collect carbon compliance payments from large emitters to invest in low-emitting technologies and processes that reduce GHG emissions, and a Climate Change Foundation promoting research and development of low carbon technologies and adaptation and fostering public education and awareness. The legislation would also establish an Environmental Code of best practices, standards and guidelines for reducing emissions. Bill 126 has not been passed.

General

The direct and indirect costs of GHG legislation, existing and proposed, may adversely affect the Company's business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce the Company's emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations requirements may materially adversely affect the Company's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by the Company or by consumers of the Company's products. The imposition of such measures might negatively affect the Company's costs and prices for the Company's products and have an adverse effect on earnings and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in western Canada. Such claims, in relation to any of BlackPearl's lands, if successful, could have an adverse effect on its operations.

BlackPearl’s interests in the Onion Lake property will be subject to processes controlled, in part, by Onion Lake Energy Ltd., which is solely owned by Onion Lake First Nation of Saskatchewan/Alberta (OLFN) and will be situated on Treaty Land Entitlement Reserves and are subject to the federal rules and regulations of Indian Oil and Gas Canada. There are risks associated with the Company’s relationship with Onion Lake Energy Ltd. and the management of BlackPearl’s interests on Treaty Land Entitlement Reserves. Specifically, a dispute could arise between BlackPearl and OLFN regarding issues such as employment, lease terms and project success. The result of such a dispute could be that OLFN denies BlackPearl, among others, access to Onion Lake lands for the exploration and production of oil and gas. In addition, the government of Canada through the governing body, Indian Oil and Gas Canada, could change the rules, leases and dispositions by which the Issuer is able to explore and operate on Onion Lake treaty lands.

Competition

The oil and gas industry is highly competitive. BlackPearl actively competes with a substantial number of other oil and gas companies for reserve acquisitions, exploration leases, licenses and concessions, access to drilling rigs and other equipment, access to processing and pipeline facilities and skilled industry personnel, many of which have significantly greater financial resources than BlackPearl. BlackPearl’s competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Reliance on Key Personnel

BlackPearl’s success depends, in part, on the performance of certain key personnel. The loss of services of such key personnel could have a material adverse affect on the Company. In addition, competition for qualified personnel in the oil and gas industry can be intense and there can be no assurance that the Company will be able to continue to attract and retain personnel necessary for the development and operation of its business.

Reliance on Other Operators

Other companies operate some of the oil and gas properties in which BlackPearl has an interest. To the extent BlackPearl is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the Company's activities may be impacted by the ability, expertise, judgment and financial capability of these operators.

Title to Properties

Although title reviews may be conducted in accordance with industry practice prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat BlackPearl's ownership claim which could result in a reduction of revenues and reserves received by the Company. Any uncertainty with respect to one or more of BlackPearl's interests could have a material adverse effect on BlackPearl's business, prospects and results of operations.

Project Risk

BlackPearl manages a number of small and large projects in conducting its business. Project delays may impact expected revenues and cash flows, and project cost overruns could make projects uneconomic. The Company's ability to complete projects depends upon numerous factors, some of which are beyond the Company's control. Some of these factors include availability of processing or pipeline capacity, availability of drilling and other equipment, the ability to assess lands, weather, unexpected cost increases, accidents, the availability of skilled labor and government licensing and other regulations.

Foreign Exchange Risk

Prices for oil and natural gas are predominantly established in US dollars and a majority of the Company's expenses are incurred in Canadian dollars. Accordingly, fluctuations in the exchange rate between the US dollar and the Canadian dollar could have a material adverse effect on the Company's revenue, cash flow and financial condition. In addition, the Company has US dollar denominated cash deposits. Fluctuations in the exchange rate between the US dollar and the Canadian dollar could result in a loss on these deposits.

Credit Risk

In the ordinary course of business, the Company enters into contractual relationships with various parties, including joint venture partners, marketers of the Company's oil and natural gas production and others. In the event these parties fail to meet their contractual obligations the failure may have a material adverse effect on the Company's business, financial condition, results of operation and prospects. As a result of downturn in economic conditions during the last two years and the contraction in the availability of credit, the likelihood of a third party failing to meet its obligations has increased.

Marketing of Oil and Natural Gas Production

The Company's business depends, in part, upon the availability, proximity and capacity of oil and gas gathering systems, pipelines, and processing facilities. Any significant disruption in the availability of these facilities could have a material adverse effect on the Company's production volumes, revenues and cash flows.

Heavy oil is characterized by high specific gravity or weight and low viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil to market and correspondingly increasing BlackPearl's operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil projects.

Corporate Matters

Certain of the directors and officers of BlackPearl are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of BlackPearl, as the case may be, and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the CBCA.

Possible Failure to Realize Anticipated Benefits of Acquisitions

BlackPearl may complete acquisitions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of any future acquisitions depends, in part, on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as BlackPearl's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with its own. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect BlackPearl's ability to achieve the anticipated benefits of these and future acquisitions.

Dividends

The Company has not paid any dividends on the BlackPearl Shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operation and financial condition of the Company as well as the need for funds to finance ongoing operations and other considerations as the Board considers relevant.

Dilution

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

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Sproule Associates Limited has evaluated the proved plus probable crude oil and natural gas reserves of the Company as at December 31, 2009 (the "Sproule Report"). No attempt was made to evaluate possible reserves. The reserves data set forth below ("Reserves Data") is based upon the evaluation by Sproule and has been prepared in accordance with NI 51-101.

The reserves data and other oil and gas information set forth below has an effective date of December 31, 2009 and a preparation date of January 15, 2010.

This was the first year Sproule was engaged to prepare a reserves evaluation for the Company. In the prior year the Company requested another independent engineer to evaluate possible ("3P") reserves on the Company's properties. The 2008 reserves report included possible reserves for the Company's SAGD project at Blackrod. In 2009, the Company elected not to undertake an evaluation of its possible reserves. Given the significant capital expenditures required and the uncertainty of the timing of those expenditures, the Company felt it was appropriate to defer further review of possible reserves until we have results from our proposed pilot project and a commitment from the Board to proceed with commercial development of the Blackrod lease.

All evaluations of future net revenue are based on forecast prices and costs and are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimated future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the assumptions used in the forecast prices and costs tables will be attained and variances could be material. The recovery and reserve estimates of the Company's crude oil and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil and natural gas reserves may be greater than or less than the estimates provided therein.

Over 99% of BlackPearl's oil and gas reserves are located within Canada, specifically Alberta and Saskatchewan. Due to the immaterial amount of the reserves and value located in the United States, unless otherwise indicated, the information related to these reserves has been combined with the reserves in Canada.

The Report on Reserves Data by Sproule in Form 51-101F2 and The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3. are attached as Schedule "A" and "B" to this Annual Information Form.

SUMMARY OF OIL AND GAS RESERVES
AS AT DECEMBER 31, 2009
FORECAST PRICES AND COSTS

	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
Reserve Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved								
Developed Producing	89.4	70	2,621.90	2,051.70	4,484	4,229	21.8	14.2
Developed Non-Producing	15.3	11.7	1,032.10	793.2	189	180	0.9	0.8
Undeveloped	5.5	4.5	6,967.10	5,042.50	240	206	0.5	0.3
Total Proved	**110.2**	**86.2**	**10,621.10**	**7,887.40**	**4,913**	**4,615**	**23.1**	**15.3**
Probable	43.8	34.1	11,744.20	8,606.20	1,659	1,539	6.8	4.5
Total Proved Plus Probable	**154**	**120.3**	**22,365.40**	**16,493.60**	**6,572**	**6,154**	**30**	**19.8**

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS AT DECEMBER 31, 2009
FORECAST PRICES AND COSTS

	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					Bef Tax Net Val
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**10%/yr ($/boe)**
Proved											
Developed Producing	117,404	107,986	100,361	94,023	88,655	117,404	107,986	100,361	94,023	88,655	35.33
Developed Non-Producing	38,930	32,594	28,022	24,613	21,997	38,930	32,594	28,022	24,613	21,997	33.53
Undeveloped	194,445	148,960	119,799	99,424	84,324	194,445	148,960	119,799	99,424	84,324	23.57
Total Proved	**350,779**	**289,541**	**248,181**	**218,060**	**194,976**	**350,780**	**289,541**	**248,181**	**218,060**	**194,976**	**28.34**
Probable	403,044	261,218	188,571	144,494	114,923	302,282	197,515	143,295	110,120	87,725	21.18
Total Proved Plus Probable	**753,823**	**550,759**	**436,752**	**362,554**	**309,899**	**653,061**	**487,055**	**391,477**	**328,179**	**282,701**	**24.73**

Notes:
NPV of FNR include all resource income: sale of oil, gas, by-product reserves, processing third-party reserves, other income. Unit values are based on net reserves volumes.
Income Taxes: Includes all resource income. Apply appropriate income tax calculations. Include prior tax pools.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED) AS AT DECEMBER 31, 2009
FORECAST PRICES AND COSTS

	Revenue	**Royalties**	**Operating Costs**	**Develop-ment Costs**	**Well Abandonment / Other Costs**	**Future Net Revenue Before Income Taxes**	**Future Income Taxes**	**Future Net Revenue After Income Taxes**
	(M$)	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**	**(M$)**
Reserves Category								
Proved	885,026	209,921	236,749	63,615	23,961	350,779	0	350,780
Proved Plus Probable	1,920,245	460,504	540,861	128,638	36,419	753,823	100,762	653,061

FUTURE NET REVENUE BY PRODUCTION GROUP
AS AT DECEMBER 31, 2009
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	3,394	35.28
	Heavy Oil (including solution gas and associated by-products)	232,365	29.07
	Natural Gas (including associated by-products)*	12,421	18.55
Proved Plus Probable			
	Light and Medium Crude Oil (including solution gas and associated by-products)	4,148	31.07
	Heavy Oil (including solution gas and associated by-products)	417,061	25.02
	Natural Gas (including associated by-products)	15,542	18.08

* Includes Corporate GCA, if applicable

Unit values are based on net reserve volumes

Definitions and Notes to Reserves Data Tables

In the tables set forth above under the heading "Statement of Reserves Data and Other Information" and elsewhere in this Annual Information Form the following definitions and notes are applicable:

1) Columns and rows may not add due to rounding.

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

3) **"Development Costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   (a) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;
   (b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
   (c) Acquire, construct and install production facilities such as flow lines, separators, treators, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
   (d) Provide improved recovery systems.

4) **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

5) **"Exploration Costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both

before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
(b) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) Dry hole contributions and bottom hole contributions;
(d) Costs of drilling and equipping exploratory well; and
(e) Costs of drilling exploratory type stratigraphic test wells.

6) **"Gross"** means:

(a) In relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share before deduction of royalties, and without including any royalty interest;
(b) In relation to wells, the total number of wells in which the Company has an interest; and
(c) In relation to properties, the total area of properties in which the Company has an interest.

7) **"Net"** means:

(a) In relation to the Company's interest in production and reserves, BlackPearl's interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
(b) In relation to wells, the total number of wells obtained by aggregating the Company's working interest in each gross well; and
(c) In relation to the Company's interest in a property, the total area in which BlackPearl has an interest multiplied by the Company's working interest.

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

(a) Analysis of drilling, geological, geophysical and engineering data;
(b) The use of established technology; and
(c) Specified economic conditions.

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

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

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
(b) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of 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.
(c) **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 is unknown.
(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

(a) At least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
(b) At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

9) **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

Pricing Assumptions

The following table summarizes the oil and natural gas reference prices, inflation rates and exchange rates utilized in the Sproule Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS AT DECEMBER 31, 2009
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Lloydblend 20.5° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2004	41.42	52.91	42.79	6.87	53.91	41.37	1.4	0.77
2005	56.46	69.29	50.3	8.58	69.13	45.2	1.3	0.826
2006	66.09	73.3	51.93	7.16	75.03	59.32	1.5	0.882
2007	72.27	77.06	82.58	6.65	77.33	63.71	2	0.935
2008	99.59	102.85	58.45	8.15	104.7	75.09	1	0.943
2009	61.63	66.2	42.79	4.19	68.13	47.07	2	0.88
Forecast								
2010	79.17	84.25	74.14	5.36	86.28	59.65	2	0.92
2011	84.46	89.99	78.29	6.21	92.16	63.72	2	0.92
2012	86.89	92.61	76.86	6.44	94.84	65.57	2	0.92
2013	90.2	96.19	78.87	7.23	98.51	68.11	2	0.92
2014	92.01	98.13	79.49	7.98	100.5	69.48	2	0.92
Thereafter				Escalation Rate of 2%				

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) The pricing assumptions were provided by Sproule.
(5) None of the Company's future production is subject to a fixed or contractually committed price.
(6) The Company's average wellhead price in 2009 was $51.44 per bbl for oil and $4.10 per Mcf for natural gas.

Reconciliation of Changes in Reserves and Future Net Revenue

The following table summarizes the changes in the Company's gross oil and gas reserves (before the deduction for royalties) from December 31, 2008 to December 31, 2009.

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

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
31-Dec-08	195	102	297	8,543	13,935	22,478	10,286	10,786	21,072	20	21	41
Extensions	0	0	0	0	0	0	23	6	19	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	-22	-14	-36	3,401	-2,485	916	-3,168	-8,872	-12,031	8	-10	-3
Discoveries	0	0	0	0	0	0	49	2	51	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	-35	-45	-80	0	0	0	0	-229	-229	0	-4	-4
Economic Factors	0	0	0	219	294	513	-215	-34	-249	0	0	0
Production	-27	0	-27	-1,542	0	-1,542	-2,061	0	-2,061	-5	0	-5
31-Dec-09	**110**	**44**	**154**	**10,621**	**11,744**	**22,365**	**4,914**	**1,659**	**6,572**	**23**	**7**	**30**

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table discloses, for each product type, the volumes of undeveloped reserves that were first attributed in each of the most recent three financial years.

	Light & Medium Oil		Heavy Oil		Natural Gas		NGLs	
	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)	1st attributed Gross (MMcf)	Cumulative Gross (MMcf)	1st attributed Gross (Mbbl)	Cumulative Gross (Mbbl)
Proved Undeveloped								
2007	0	16	5,845	10,131	575	1,747	0	0
2008	4	4	0	3,375	1	579	0	0
2009	6	6	3,819	6,967	2	240	0.5	0.5
Probable Undeveloped								
2007	0	40	14,628	22,729	1,289	2,877	0	0
2008	2	50	0	8,921	1	1,429	0	0
2009	4	4	2396	8579	1	374	0.9	0.9

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

BlackPearl has a significant level of undeveloped reserves relative to developed reserves. The majority of undeveloped reserves assigned by Sproule were to the Onion Lake and the Mooney fields.

At Onion Lake, Sproule assigned undeveloped reserves to 123 future drilling locations. In 2010, we have plans to drill 50 of these locations and we will likely drill an additional 50 of these locations in 2011. The high level of undeveloped reserves relative to developed reserves at Onion Lake is due to the relatively immaturity of the field. As the field's primary development progresses it is expected that the ratio of undeveloped to developed reserves will fall.

At Mooney, undeveloped reserves were assigned for a conversion of a portion of the field to a polymer flood. It is our intention to begin the first commercial phase of the polymer flood late in 2010, subject to regulatory approval. Given the time required to obtain regulatory approval, construction time, the injection time before initial response and time to analyze the results, it is not expected that further phases of the polymer flood would begin within the next two years. The actual number of wells drilled could change as a result of changes in, among other items, economic conditions, technical and operating results, or changing priorities during our budget review process. The high level of undeveloped reserves to developed reserves at Mooney reflects the future implementation of the ASP flood and its associated reserves. Following the implementation of the ASP flood the ratio of undeveloped to developed reserves is expected to decline.

A portion of the Company's capital budget is allocated to new projects or projects that do not have reserves assigned as yet. As a result, all capital required to develop the undeveloped reserves may not be spent in the next two years.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

We have a significant amount of proved undeveloped and probable undeveloped reserves assigned to our Mooney field in northern Alberta. At current prices, this development is economic; however, should oil prices fall materially, this project could become uneconomic (as a result of relatively high royalties and operating costs) and development could be deferred.

Future Development Costs

The following table sets forth development costs deducted in the estimation of future net revenue attributable to the reserve categories below.

($000's)	Total Proved	Total Proved Plus Probable
2010	23,723	39,591
2011	35,093	63,108
2012	2,419	7,865
2013	1,390	16,687
2014	42	118
Remainder	948	1,269
Total for all years undiscounted	63,615	128,638
Total for all years discounted at 10% per year	56,348	110,700

The Company expects to fund future development costs from existing working capital, internally generated cash flow, and debt or equity financings. The Company does not anticipate that interest or other funding costs would make development of these projects uneconomic.

There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves in the reserve reports. Failure to develop those reserves would have a negative impact on future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

OTHER OIL AND GAS INFORMATION

OIL AND GAS WELLS

The following table summarizes BlackPearl's gross and net interests in oil and natural gas wells in which it has a working interest as at December 31, 2009:

	Oil wells				Gas wells			
	Producing		Non-producing		Producing		Non-producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada	152	114.2	327	281.4	178	144.2	160	123.6
US	0	0.0	4	1.1	20	12.0	5	1.4
Total	152	114.2	331	282.6	198	156.2	165	125.0

LAND HOLDINGS INCLUDING PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets out the developed and undeveloped land holdings as at December 31, 2009.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	99,652	60,432	135,202	115,311	234,854	175,743
Saskatchewan	53,367	50,223	120,183	113,389	173,549	163,612
British Columbia	695	174	2,085	261	2,780	434
Total - Canada	153,713	110,829	257,469	228,961	411,183	339,789
Total - USA	4,406	1,606	160,716	139,241	165,123	140,847
Total	158,120	112,435	418,186	368,202	576,306	480,637

We currently have no material work commitments on these lands. Over the next 12 months, 61,252 net acres of BlackPearl's undeveloped land will be subject to expiry.

FORWARD CONTRACTS

As at December 31, 2009, BlackPearl did not have any fixed price contracts to sell any of its production. The majority of the Company's production is sold under short-term contracts.

ABANDONMENT AND RECLAMATION COSTS

The following table summarizes the estimate for abandonment and reclamation costs included in the report by Sproule for wells that have reserves assigned. Only well abandonment costs, net of downhole salvage value were deducted by Sproule in estimating future net revenue in the Sproule report. In addition, the Company uses internal estimates for wells that do not have reserves assigned. The total undiscounted estimates for abandonment and reclamation (before salvage value) for all wells and facilities of the Company was $38.3 million at December 31, 2009. The internal estimates have not been deducted in estimating the future net revenue by Sproule. BlackPearl expects to incur abandonment and reclamation costs on approximately 874 net wells.

Year	**Total Proved (M$)**	**Total Proved Plus Probable (M$)**
2010	3,580	4,017
2011	4,367	5,542
2012	3,377	5,412
2013	2,384	3,942
2014	1,749	2,493
Remaining	8,504	15,013
Total (Undisc)	23,961	36,419
Total (Disc at 10%)	16,320	23,078

BlackPearl has not established a reclamation fund to pay future asset retirement obligation costs. During 2009, the Company incurred $0.6 million to abandon and reclaim sites.

TAX HORIZON

On a total proved reserves basis, estimates of net income indicate that the Company will not be taxable. Estimates of net income on a proved and probable basis indicate the Company will be taxable in 2016.

COSTS INCURRED

The following table summarizes capital expenditures made by BlackPearl on oil and natural gas properties for the year ended December 31, 2009.

	2009 ($ thousands)		
	Canada	U.S.	Total
Property acquisition costs - proved	-	-	-
Property acquisition costs - unproved	-	-	-
Exploration costs (1)	4,438	2,104	6,542
Development costs	21,336	-	21,336
Total	25,774	2,104	27,878

Note:

(1) Includes costs of land, geological and geophysical expenses and drilling costs for exploration wells.

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number of gross and net exploratory and development wells BlackPearl participated in drilling for the year ended December 31, 2009.

	Development wells		**Exploratory wells**	
	Gross	**Net**	**Gross**	**Net**
Oil wells	29	25.5	2	2.0
Gas wells	4	0.2	0	0.0
Evaluation wells	10	8.0	0	0.0
Dry	0	0.0	1	0.4
Total	43	33.7	3	2.4

All of the wells drilled in 2009 were located in Canada, and all of our planned activities for 2010 are located in Canada.

PRODUCTION ESTIMATES

The following table sets out the estimated production volumes for the year ended December 31, 2009 which is reflected in the estimate of gross and gross probable reserves disclosed in the tables contained under "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data".

	Gross Daily Production Total
Total Proved	
Light & Medium Oil (bbl/d)	56
Heavy Oil (bbl/d)	4,928
Assoc. and Non-Assoc. Gas (Mcf/d)	3,605
Natural Gas Liquids (bbl/d)	17
Total (boe/d)	**5,601**
Total Probable	
Light & Medium Oil (bbl/d)	2
Heavy Oil (bbl/d)	676
Assoc. and Non-Assoc. Gas (Mcf/d)	199
Natural Gas Liquids (bbl/d)	2
Total (boe/d)	**714**
Total Proved + Probable	
Light & Medium Oil (bbl/d)	58
Heavy Oil (bbl/d)	5,604
Assoc. and Non-Assoc. Gas (Mcf/d)	3,804
Natural Gas Liquids (bbl/d)	19
Total (boe/d)	**6,315**

The Onion Lake field in Saskatchewan accounts for 68% (4,315 boe/day) of BlackPearl's total forecasted gross 2010 production.

PRODUCTION HISTORY

The following table indicates the Company's average daily production from its significant fields in 2009 and 2008:

	2009			2008		
	Oil(bbl/d)[(1)]	Gas(mcf/d)	boe/d	Oil(bbl/d)[(1)]	Gas(mcf/d)	boe/d
Onion Lake	2,276	128	2,297	2,217	366	2,278
Mooney	1,178	1,469	1,423	1,671	2,605	2,105
Ear Lake	424	145	448	360	140	383
Salt Lake	262	543	353	389	794	521
LongCoulee/Little Bow	9	2,407	410	10	3,362	570
Other	125	890	323	1,535	1,675	1,815
	4,324	5,582	5,254	6,182	8,942	7,672

Note:

(1) Includes natural gas liquids

NETBACKS

	Quarter Ended				Year Ended
	Mar. 31, 2009	Jun. 30, 2009	Sep. 30, 2009	Dec. 31, 2009	2009
Average Daily Production (1)(2)					
Oil (bbl/d)	4,422	4,167	4,247	4,506	4,324
Natural Gas (mcf/d)	6,527	6,017	5,065	4,801	5,582
Average Net Prices Received					
Oil ($/bbl)	31.99	53.33	58.53	61.77	51.44
Natural Gas ($/mcf)	5.08	3.51	3.05	4.62	4.10
Transportation Costs (3)					
Oil ($/bbl)					
Natural Gas ($/mcf)					
Products Combined ($/boe)	2.63	1.46	1.58	1.52	1.81
Royalties					
Oil ($/bbl)	7.33	14.38	16.66	15.98	13.60
Natural Gas ($/mcf)	(0.00)	(0.71)	0.39	0.27	(0.04)
Production Costs (3)					
Oil ($/bbl)					
Natural Gas ($/mcf)					
Products Combined ($/boe)	20.50	12.48	13.32	14.85	15.36
Netback Received (5)					
Oil ($/bbl)					
Natural Gas ($/mcf)					
Netback Received Combined ($/boe)	2.85	22.38	22.79	26.52	18.48

Notes:

(1) Light and Medium Crude Oil and Natural Gas Liquids are not material and have been grouped with Heavy Oil volumes for reporting purposes.
(2) Before deduction of royalties.
(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. The majority of our gas volumes are associated gas from oil wells and, therefore, we have reported production costs and netbacks on a boe basis.
(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalties, transportation costs and production expenses from revenues.

DIVIDENDS

There are no restrictions which prevent BlackPearl from paying dividends. To date, BlackPearl has not paid any dividends on the BlackPearl Shares. The future payment of dividends will depend on the earnings and financial condition of BlackPearl and such other factors as the Board considers appropriate. The Company does not intend to pay dividends on BlackPearl Shares in the foreseeable future.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of BlackPearl consists of an unlimited number of BlackPearl Shares. As at February 25, 2010, there were 262,024,051 BlackPearl Shares issued and outstanding.

The following is a summary of the rights, privileges and conditions attaching to the BlackPearl Shares. Each BlackPearl Share entitles the holder to receive notice of and to attend all meetings of the shareholders of the Company and to one vote at such meetings. The holders of BlackPearl Shares are, at the discretion of the Board and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board. The holders of BlackPearl Shares are entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among its shareholders for the purpose of winding-up its affairs.

MARKET FOR SECURITIES

Trading Price and Volume

The BlackPearl Shares are listed and posted for trading on the TSX and trade under the symbol "PXX". The Company's Swedish Depository Receipts trade on First North, OMX Nordic Exchange under the symbol "PXXS". The following sets forth the price range and trading volume of the BlackPearl Shares on the TSX for the periods indicated.

2009	High ($/Share)	Low ($/Share)	Volume
January	1.05	0.78	7,408,873
February	0.95	0.67	3,965,834
March	0.97	0.62	5,017,482
April	1.35	0.86	13,592,230
May	1.74	1.12	24,717,778
June	1.60	1.25	13,180,323
July	1.53	1.25	11,348,179
August	1.74	1.50	8,637,021
September	1.99	1.47	12,221,163
October	2.31	1.75	15,679,315
November	2.62	2.03	7,878,745
December	2.60	2.31	6,027,225

Prior Sales

On April 20, 2009, the Company completed a financing consisting of 52,334,000 special warrants at a price of $0.88 per special warrant representing gross proceeds of approximately $46 million on a bought deal basis. Each special warrant was converted into one BlackPearl Share on May 6, 2009 for no additional consideration.

DIRECTORS AND EXECUTIVE OFFICERS

The following table sets forth the name, municipality of residence, principal occupation for the prior five years and position of each of the directors and executive officers of BlackPearl:

Name and Residence	Principal Occupation for Past Five Years	Position	Date Appointed	Security Holdings (5)
Keith C. Hill (4) West Vancouver, British Columbia, Canada	Mr. Hill is President and Chief Executive Officer of Africa Oil Corp. He was the President and Chief Executive Officer of BlackPearl from February 2007 to January 8, 2009. Mr. Hill was President, CEO and a director of Valkyries Petroleum Corp. from August 2002 to July 2006.	Chairman and Director	Jan. 2006	578,400 (6) 1,400,000 (7)
John H. Craig (1)(2)(3) Toronto, Ontario, Canada	Mr. Craig is a lawyer and partner of Cassels Brock & Blackwell LLP.	Director	May 2009	75,000 (6) 300,000 (7)
Brian D. Edgar (1)(2)(3)(4) Vancouver, British Columbia, Canada	Mr. Edgar is President and Chief Executive Officer of Dome Ventures Corporation.	Director	Feb. 2006	412,500 (7)
John L. Festival Calgary, Alberta, Canada	Mr. Festival is President and Chief Executive Officer of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was President of BlackCore Resources Inc. From January 2001 to June 2006, Mr. Festival was President and a Director of BlackRock Ventures Inc.	Officer and Director	Jan. 2009	5,825,000 (6) 1,250,000 (7) 2,411,299 (8)
Victor Luhowy (1)(2)(3)(4) Priddis, Alberta, Canada	Mr. Luhowy is President, BelAir Petroleum Management Ltd. From February 2004 to June 2009, Mr. Luhowy was President and Chief Executive Officer of Mystique Energy Inc.	Director	Jan. 2009	50,000 (6) 300,000 (7)

Name and Residence	Principal Occupation for Past Five Years	Position	Date Appointed	Security Holdings [5]
Don Cook Calgary, Alberta, Canada	Mr. Cook is Chief Financial Officer of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Finance of BlackCore Resources Inc. From 1999 to June 2006 he was Vice President, Finance, Chief Financial Officer and Secretary of BlackRock Ventures Inc.	Officer	Jan. 2009	5,825,000 [6] 1,250,000 [7] 2,411,299 [8]
Edward Sobel Calgary, Alberta, Canada	Mr. Sobel is Vice President Exploration of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Exploration of BlackCore Resources Inc. From August 2007 to January 2009 he was VP Geology of Soho Resources Ltd. From 1999 to June 2006 he was Manager Geology of BlackRock Ventures Inc.	Officer	Jan. 2009	5,182,600 [6] 1,250,000 [7] 2,411,299 [8]
Chris Hogue Calgary, Alberta, Canada	Mr. Hogue is Vice President Operations of BlackPearl since January 8, 2009. From October 2007 to January 2009, he was Vice President, Operations of BlackCore Resources Inc. From August 2007 to January 2009 he was VP Operations of Soho Resources Ltd. From July 2006 to August 2007, Mr. Hogue was Operations Manager, Heavy Oil at Shell Canada Ltd. From 2002 to June 2006 he was Manager Operations of BlackRock Ventures Inc.	Officer	Jan. 2009	2,662,500 [6] 1,250,000 [7] 2,411,299 [8]
Diane Phillips Calgary, Alberta, Canada	Ms. Phillips has been the Corporate Secretary of BlackPearl since August 2006. From February 2006 to December 2008, Ms. Phillips was the Corporate Secretary of Tanganyika Oil Company Ltd. From 2002 to 2006, she was Assistant Corporate Secretary of Viking Energy Royalty Trust.	Officer	Aug. 2006	3,000 [6] 140,500 [7]

Notes:

(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Nominating Committee Committee.
(3) Member of the Compensation Committee.
(4) Member of the Reserves Committee.
(5) The information as to shares beneficially owned, not being within the knowledge of the Company, has been provided by the respective officers and directors.
(6) BlackPearl Shares
(7) Stock Options
(8) Warrants

The term of office of each of the directors of BlackPearl will expire at the next annual meeting of shareholders of BlackPearl.

As at December 31, 2009, our directors and executive officers, as a group, beneficially owned, or controlled or directed, directly or indirectly, 20,201,500 BlackPearl Shares or approximately 8% of the issued and outstanding BlackPearl Shares. In addition, directors and executive officers held 9,645,196 warrants and 6,030,000 options resulting in directors and executive officers holding 13% of the BlackPearl Shares on a fully diluted basis. The information as to BlackPearl Shares beneficially owned, not being within the knowledge of the Company, has been furnished by the respective individuals.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as discussed below, no director, executive officer or controlling security holder of BlackPearl is, as at the date of this Annual Information Form, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that: (i) while that person was acting in that capacity was the subject of: (i) a cease trade order or similar order; or (ii) an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (collectively an "Order"); (ii) was subject to an Order after the person ceased to be a director or executive officer, which resulted from an event that occurred while that person was acting that capacity; or (iii) 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.

Mr. Brian Edgar is currently and was a director of New West Energy Services Inc. (TSX-V) when, on September 5, 2006, a cease trade order was issued against that company by the British Columbia Securities Commission for failure to file its financial statements within the prescribed time. The default was rectified and the order was rescinded on November 9, 2006. Mr. Edgar resigned as a director of New West Energy Services Inc. on August 24, 2009.

Mr. Victor Luhowy was formerly President and Chief Executive Officer of Mystique Energy Inc., which on April 24, 2007 filed for and obtained protection from its creditors under the *Companies Creditors Arrangement Act*.

Personal Bankruptcies

No director, executive officer or controlling security holder of BlackPearl has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No director, executive officer or controlling security holder of BlackPearl has: (i) been subject to 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, other than penalties for late filing of insider reports; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE INFORMATION

The Audit Committee of the Board consists of three members, all of whom are independent: Brian D. Edgar, Victor Luhowy and John Craig.

The responsibilities and duties of the Audit Committee are set out in the Audit Committee's charter which is set forth in Schedule "C" to this Annual Information Form.

Composition of the Audit Committee

At December 31, 2009, the audit committee was comprised of the following individuals:

	Independent [1]	**Financially literate [1]**	**Relevant Education and Experience**
Brian Edgar	Yes	Yes	Law degree with 16 year practice as a corporate/securities lawyer. Extensive experience with management of public companies.
Victor Luhowy	Yes	Yes	Education includes B.Sc. in Engineering and Masters of Business Administration. Extensive experience with management of public companies.
John Craig	Yes	Yes	Education includes law degree and BA (Economics) and over 30 years experience as a director of public companies. As a securities lawyer, required to review financial statements as part of responsibilities in carrying out legal services.

Note:

As defined by National Instrument 52-110 *Audit Committees*.

Pre-Approval Policies and Procedures

The audit committee has adopted specific policies and procedures for the engagement of non-audit services as described under the heading "Accounting Systems, Internal Control and Procedures" in the Audit Committee's Charter which is attached as Schedule "C" to this Annual Information Form..

Audit Fees

The following table summarizes the fees earned by the Company's independent auditors, PricewaterhouseCoopers LLP, for the years ended December 31, 2009 and 2008. Tax services were provided by KPMG LLP.

Financial Year	Audit Related Fees	Tax Fees	All Other Fees
2009	$329,806	$32,428	$95,529
2008	$226,172	$29,499	$13,069

CONFLICTS OF INTEREST

The Company's directors and officers may serve as directors or officers of other companies or have significant shareholdings in other resource companies and, to the extent that such other companies may participate in ventures in which the Company may participate, the directors of the Company may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Company's directors, a director who has such a conflict will abstain from voting for or against the approval of such a participation or the terms of such participation. From time to time, several companies may participate in the acquisition, exploration and development of natural resource properties, thereby allowing for their participation in larger programs, the involvement in a greater number of programs or a reduction in financial exposure in respect of any one program. It may also occur that a particular company will assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment. In accordance with the laws of Canada, the directors or the Company are required to act honestly, in good faith and in the best interests of the Company. In determining whether or not the Company will participate in a particular program and the interest therein to be acquired by it, the directors will primarily consider the degree of risk to which the Company may be exposed and the financial position at that time.

The directors and officers of the Company are aware of the existence of laws governing the accountability of directors and officers for corporate opportunity and requiring disclosure by the directors of conflicts of interest and the Company will rely upon such laws in respect of any directors' and officers' conflicts of interest or in respect of any breaches of duty by any of its directors and officers. All such conflicts will be disclosed by such directors or officers in accordance with the *Canada Business Corporations Act* and they will govern themselves in respect thereof to the best of their ability in accordance with the obligations imposed upon them by law. Other than as disclosed above, the directors and officers of the Company are not aware of any such conflicts of interest in any existing or contemplated contracts with or transactions involving the Company.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Neither BlackPearl nor any of its subsidiaries is or was a party to, or has or had any property subject to, any legal proceedings during the financial year ended December 31, 2009 that are material to the Company, or knows of any such legal proceedings contemplated.

During the year ended December 31, 2009, there have not been any penalties or sanctions imposed against BlackPearl by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and BlackPearl has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of directors, executive officers of the Company or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding BlackPearl Shares 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 Company.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Company are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta T2P 5L3.

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business and not of the type required in any event to be disclosed pursuant to Part 12 of NI 51-102, there are no contracts entered into by BlackPearl or any of its subsidiaries within the last financial year, or entered into before the last financial year but still in effect, which the Company considers to be material as at the date of this Annual Information Form.

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 NI 51-102 by BlackPearl during the current financial year other than Sproule, BlackPearl's independent engineering evaluators and PricewaterhouseCoopers LLP, BlackPearl's auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of BlackPearl or of BlackPearl's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP, BlackPearl's auditors, are independent in accordance with the auditor's rules of professional conduct in Canada.

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 BlackPearl or any associate or affiliate of BlackPearl.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular and proxy statement for the Company's annual meeting of shareholders to be held on May 12, 2010. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the period ended December 31, 2009.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph and any other document incorporated herein by reference are available on the foregoing basis and upon request by contacting the Corporate Secretary at 700, 444 – 7 Avenue S.W., Calgary, Alberta, T2P 0X8, Canada, by phone at (403) 213-8768 or by fax at (403) 265-8324.

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of BlackPearl Resources Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of BlackPearl Resources Inc., As of December 31, 2009, prepared October 2009 to January 2010	Canada				
Total			**Nil**	**436,752**	**Nil**	**436,752**

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
January 15, 2010

Original signed by Colleen M. Rogers

Colleen M. Rogers, C.E.T., Shareholder
Project Leader

Original signed by Alec Kovaltchouk

Alec Kovaltcouk, P.Geol.
Associate

Original signed by Doug W. C. Ho

Doug W. C. Ho, P.Eng.
Vice-President, Engineering

FORM 51-101F3
REPORT OF MANAGEMENT ON OIL AND GAS DISCLOSURE
BLACKPEARL RESOURCES INC.

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI51-101").

1. Terms to which a meaning is ascribed in NI51-101 have the same meaning in this form.

2. The report referred to in item 3 of section 2.1 of NI51-101 must in all material respects be as follows:

Report of Management and Directors on Reserves Data and Other Information

Management of BlackPearl Resources Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

Sproule Associates Limited, independent qualified reserves evaluators, have evaluated the Company's reserves data. The report of Sproule Associates Limited has been presented on Form 51-101F2.

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

(a) reviewed the Company's procedures for providing information to Sproule Associates Limited;

(b) met with Sproule Associates Limited to determine whether any restrictions affected the ability of Sproule Associates Limited to report without reservation.

(c) reviewed the reserves data with management and Sproule Associates Limited.

The board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management and management has 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 Sproule Associates Limited on the reserves data; and

(c) the content and filing of this report.

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

“signed”	*“signed”*
John L. Festival	Don W. Cook
President and Chief Executive Officer	Chief Financial Officer
“signed”	*“signed”*
Keith Hill	Brian Edgar
Director	Director

February 24, 2010

BLACKPEARL RESOURCES INC.
(the “Corporation”)

Audit Committee of the Board of Directors
(the “Audit Committee”)

CHARTER

1. Composition and Process

(a) The Audit Committee shall be composed of a minimum of three members of the Board of Directors, a majority of whom are independent. An independent director, as defined in *Multilateral Instrument 52-110, Audit Committees*, (“MI 52-110”) is a director who has no direct or indirect material relationship which could , in the view of the Corporation’s board of directors, be reasonably expected to interfere with the exercise of a members independent judgement or as otherwise determined to be independent in accordance with MI 52-110.

(b) Members of the Audit Committee shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.

(c) The Chairperson of the Audit Committee shall be appointed by the Board of Directors for a one-year term, and may serve any number of consecutive terms.

(d) All members of the Audit Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity comparable to the Corporation’s financial statements.

(e) The Chairperson of the Audit Committee shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the Audit Committee members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Audit Committee. The Audit Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.

(f) The Audit Committee shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Audit Committee shall be its Chairperson and one of its other members or the Chairman of the Board of Directors. The Audit Committee may hold its meetings, and members of the Audit Committee may attend meetings, by telephone conference if this is deemed appropriate.

(g) The minutes of the Audit Committee meetings shall accurately record the decisions reached and shall be distributed to Audit Committee members with copies to the Board of Directors, the Chief Executive Officer, the Chief Financial Officer and the external auditor.

(h) The Audit Committee shall review, prior to their presentation to the Board of Directors and their release, all material financial information required by securities legislation and policies.

(i) The Audit Committee shall enquire about potential claims, assessments and other contingent liabilities.

(j) The Audit Committee shall periodically review with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

(k) The Charter of the Audit Committee shall be reviewed by the Board of Directors on an annual basis.

2. <u>Authority</u>

(a) The Audit Committee is appointed by the Board of Directors pursuant to provisions of the *Canada Business Corporations Act* and the bylaws of the Corporation.

(b) The Audit Committee's primary responsibility is to ensure that the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board of Directors. The Audit Committee is a standing committee of the Board of Directors established to assist it in fulfilling its responsibilities in this regard. The Audit Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Audit Committee to ensure that management has done so.

(c) In fulfilling its responsibilities, the Audit Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.

(d) The Audit Committee shall have direct communication channels with the internal auditor (if any) and the external auditor to discuss and review specific issues, as appropriate.

(e) The Audit Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.

(f) The Audit Committee shall establish the compensation to be paid to any advisors employed by the Audit Committee and such compensation shall be paid by the Corporation as directed by the Audit Committee.

3. <u>Relationship with External Auditors</u>

(a) An external auditor must report directly to the Audit Committee.

(b) The Audit Committee is directly responsible for overseeing the work of the external auditor including the resolution of disagreements between management and the external auditor regarding financial reporting.

(c) The Audit Committee shall implement structures and procedures to ensure that it meets with the external auditor at least annually in the absence of management.

4. <u>Accounting Systems, Internal Controls and Procedures</u>

(a) The Audit Committee shall:

(i) obtain reasonable assurance from discussions with and/or reports from management and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates;

(ii) review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures;

(iii) direct the external auditor's examinations to particular areas;

(iv) review control weaknesses identified by the external auditor, together with management's response; and

(v) review with the external auditor its view of the qualifications and performance of the key financial and accounting executives.

(b) In order to preserve the independence of the external auditor, the Audit Committee will:

(i) recommend to the Board of Directors the external auditor to be nominated; and

(ii) recommend to the Board of Directors the compensation of the external auditor's engagement.

(c) The Audit Committee shall:

(i) review and pre-approve any engagements for non-audit services to be provided by the external auditor or its affiliates, together with estimated fees, and consider the impact on the independence of the external auditor;

(ii) review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties and key estimates and judgments of management that may be material to financial reporting;

(iii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and most recent former external auditor of the Corporation;

(iv) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters; and

(v) on an annual basis, prior to public disclosure of its annual financial statements, ensure that the external auditor has entered into a participation agreement and has not had its participant status terminated, or, if its participant status was terminated, has been reinstated in accordance with the Canadian Public Accountability Board ("CPAB") bylaws and is in compliance with any restriction or sanction imposed by the CPAB.

5. Statutory and Regulatory Responsibilities

(a) *Annual Financial Information*. The Audit Committee shall review the annual audited financial statements, including any letter to shareholders and related press releases and recommend their approval to the Board of Directors, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.

(b) *Annual Report*. The Audit Committee shall review the management discussion and analysis ("MD&A") section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.

(c) *Interim Financial Statements*. The Audit Committee shall review the quarterly interim financial statements, including any letter to shareholders and related press releases, and recommend their approval to the Board of Directors.

(d) *Earnings Guidance/Forecasts*. The Audit Committee shall review forecasted financial information and forward looking statements.

(e) The Audit Committee shall review the Corporation's financial statements, MD&A and earnings press releases before the Corporation publicly discloses this information.

6. Reporting

The Audit Committee shall:

(a) report, through the Chairperson of the Audit Committee, to the Board of Directors following each meeting on the major discussions and decisions made by the Audit Committee;

(b) report annually to the Board of Directors on the Audit Committee's responsibilities and how it has discharged them; and

(c) review the Audit Committee's Charter annually and recommend the approval of any proposed amendments to the Board of Directors.

7. Other Responsibilities

The Audit Committee shall:

(a) investigate fraud, illegal acts or conflicts of interest; and

(b) discuss selected issues with corporate counsel or the external auditor or management.