



**BLACKPEARL RESOURCES INC.**

**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED DECEMBER 31, 2010**

February 25, 2011

## TABLE OF CONTENTS

Glossary Of Terms.....	3
Abbreviations.....	4
Conversions .....	4
Introductory Information.....	5
Forward Looking Statements.....	5
Corporate Structure.....	6
General Development Of Our Business .....	7
Description Of Our Business .....	9
Risk Factors .....	20
Statement Of Reserves Data And Other Oil And Gas Information.....	27
Other Oil And Gas Information .....	37
Dividends .....	41
Description Of Capital Structure .....	41
Market For Securities.....	41
Directors And Executive Officers .....	42
Audit Committee Information .....	44
Conflicts Of Interest .....	45
Legal Proceedings And Regulatory Actions.....	46
Interest Of Management And Others In Material Transactions .....	46
Auditors, Transfer Agent And Registrar .....	46
Material Contracts .....	46
Interests Of Experts .....	46
Additional Information .....	47

## 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, 2010, dated February 25, 2011;

"**ASP**" means Alkali Sufactant Polymer

"**BlackCore**" means BlackCore 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;

"**BCA**" 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;

"**ERCB**" means Energy Resources Conservation Board (Alberta);

"**IFRS**" means International Financial Reporting Standards;

"**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.;

"**SOR**" means steam oil ratio

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

"**Sproule Report**" means the report prepared by Sproule dated January 18, 2011 evaluating the oil and gas reserves attributable to BlackPearl's properties as at December 31, 2010 and the contingent resource reports prepared by Sproule dated January 18, 2011 for the Blackrod, Onion Lake and Mooney properties as at December 31, 2010;

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

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

## ABBREVIATIONS

### General

<b>AECO</b>	Intra-Alberta Nova Inventory Transfer Price (NIT net price)
<b>API</b>	American Petroleum Institute
<b>°API</b>	An indication of the specific gravity of crude oil measured on the API gravity scale
<b>boe</b>	Barrel of oil equivalent on the basis of 1 boe to 6 Mcf. 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.
<b>boe/d</b>	Barrel of oil equivalent per day
<b>m3</b>	Cubic metres
<b>WTI</b>	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

### Oil and Natural Gas Liquids

<b>bbl</b>	barrel
<b>bbls</b>	barrels
<b>bbls/d</b>	barrels of oil per day
<b>Mbbls</b>	thousand barrels
<b>NGLs</b>	natural gas liquids
<b>stb</b>	stock tank barrel

### Natural Gas

<b>Bcf</b>	billion cubic feet
<b>GJ</b>	gigajoule
<b>GJ/d</b>	gigajoule per day
<b>Mcf</b>	thousand cubic feet
<b>Mcf/d</b>	thousand cubic feet per day
<b>MMcf</b>	million cubic feet
<b>MMcf/d</b>	million cubic feet per day

## CONVERSIONS

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Acres	Hectares	0.405
bbls	Cubic metres	0.159
Cubic metres	bbls	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.

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 references 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 or forward-looking information. Forward-looking statements and forward-looking information 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 and forward-looking information. We believe the expectations reflected in those forward-looking statements and forward-looking information 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 and contingent resources;
- net present values of future net revenues from reserves and contingent resources;
- anticipated production levels;
- abandonment and reclamation costs;
- projections of oil and gas 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;
- construction and completion of facilities; and
- treatment under governmental regulatory and royalty regimes and tax laws

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that the goals or figures contained in forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with fluctuations in market prices for crude oil, natural gas and diluent, general economic, market and business conditions, substantial capital requirements, uncertainties inherent in estimating quantities of reserves and resources, extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time, the need to obtain regulatory approvals on projects before development commences, environmental risks and hazards and the cost of compliance with environmental regulations, aboriginal claims, inherent risks and hazards with operations such as fire, explosion, blowouts, mechanical or pipe failure, cratering, oil spills, vandalism and other dangerous conditions, potential cost overruns, variations in foreign exchange rates, diluent supply shortages, competition for capital, equipment, new leases, pipeline capacity and skilled personnel, uncertainties inherent in the SAGD bitumen and Alkali Surfactant Polymer recovery processes, credit risks associated with counterparties, the failure of the Company or the holder of licenses, leases and permits to meet requirements of such licenses, leases and permits, reliance on third parties for pipelines and other infrastructure, changes in royalty regimes, failure to accurately estimate abandonment and reclamation costs, inaccurate estimates and assumptions by management, effectiveness of internal controls, the potential lack of available drilling equipment and other restrictions, failure to obtain or keep key personnel, title deficiencies with the Company's assets,

geo-political risks, risks that the Company does not have adequate insurance coverage, risk of litigation and risks arising from future acquisition activities. Further information regarding these risk factors may be found under “Risk Factors” in this Annual Information Form.

With respect to forward-looking statements contained in this report, management has 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 and contingent resources are forward-looking, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources 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 and forward-looking information, 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 and forward-looking information will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements and forward-looking information 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, assumption 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 statements and 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 the foregoing cautionary statements.

## **BLACKPEARL RESOURCES INC.**

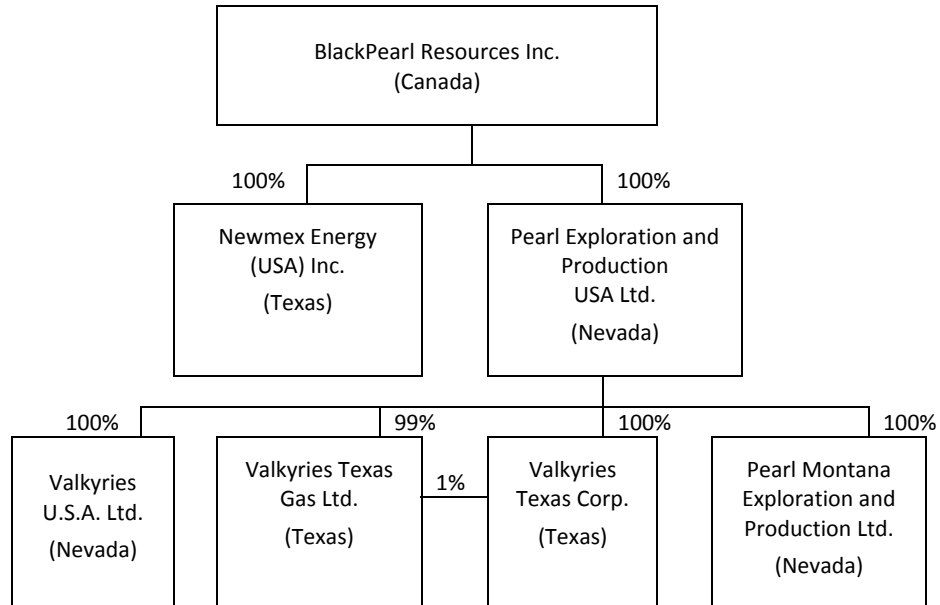
### **GENERAL**

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

BlackPearl was incorporated under the *Business Corporations Act* (Alberta) 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 into federal jurisdiction pursuant to the *Canada Business Corporations Act*. 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.

### **Corporate Structure**

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 December 31, 2010.



## **GENERAL DEVELOPMENT OF OUR BUSINESS**

### **Overview**

BlackPearl's principal business is the acquisition, development and production of heavy oil and bitumen. The majority of BlackPearl's oil and gas interests are located in Canada.

At the present time, the majority of the Company's production is from conventional heavy oil projects; however, the Company is actively developing oil projects that utilize SAGD extraction methods. BlackPearl is not engaged in oil sands mining.

Initially, BlackPearl's strategy was to grow and develop the Company through a combination of acquisitions and internal development of its properties.

From 2006 to 2009, the Company completed six corporate acquisitions, as well as a number of property acquisitions. During this period, the Company spent \$412 million on corporate acquisitions and an additional \$373 million on property acquisitions and internal development.

In 2009, the Board of Directors retained a new management group with a revised business plan. The plan was to focus exclusively on conventional heavy oil and oil sands projects and to grow primarily by internally developing its projects rather than through acquisition. The new plan is to concentrate on the three core properties of Onion Lake, Blackrod and Mooney, all in western Canada, and over time, dispose of all other non-core assets.

### **Three Year History**

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

#### *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. BlackPearl had previously acquired a 35% interest in the Blackrod oilsands leases at an Alberta crown land sale in 2007. 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.

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 of Texas 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 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 Chief Executive Officer; 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 BlackPearl's 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 work commitment of \$5 million. As a result of the agreements, the Company became 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.

#### *Year Ended December 31, 2010*

On January 1, 2010, the Company amalgamated its wholly-owned subsidiary Pearl E&P Canada Ltd., with BlackPearl Resources Inc.

On March 29, 2010, the Company acquired the remaining 20% working interest in the Blackrod area, located in the Athabasca oil sands, from Serrano Energy Ltd. for \$21 million. The acquisition resulted in BlackPearl having a 100% working interest in the Blackrod area lands.

On May 11, 2010, the Company issued 10,350,000 common shares at a price of \$2.90 per share, for aggregate gross proceeds of \$30 million.

On October 18, 2010, the Company announced it had received approval from the ERCB to proceed with development of the first phase of its alkali surfactant polymer flood at Mooney. The Company also announced that the ERCB also approved BlackPearl's application for the construction and operation of its SAGD pilot at Blackrod.

On December 7, 2010 the Company issued 6,000,000 common shares at a price of \$5.00 per share, for aggregate gross proceeds of \$30 million.

## **DESCRIPTION OF OUR BUSINESS**

### **Heavy Oil and Bitumen 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. Bitumen and some heavy oil is highly viscous and they will not flow to a well bore on their own accord in commercial quantities. This is typical in the oil sands region in northern Alberta. This highly viscous heavy oil can be 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 ultimately upgraded to synthetic oil. Generally, if the oil sands deposit is less than 100 metres deep, it is usually extracted using a mining operation. If the deposit is greater than 100 metres, the oil is usually extracted using an in situ recovery method. The oil is encouraged to flow to well bores through the application of external energy, such as heat. The two most common in situ recovery methods in the Canadian oil sands include SAGD and CSS. SAGD technology involves drilling steam injection and oil production wells (generally horizontal wells). Steam is injected in the upper well at low pressure which melts or loosens the heavy oil or bitumen which allows it to flow downward to the second well where it is collected and pumped to the surface. CSS technology involves injecting steam and producing oil from the same well bore. Steam is injected at high pressure for a period of time, allowed to soak and then the well is converted to oil production. This cycle is repeated a number of times. Historically, recovery rates have been higher using SAGD technology. Most in situ recovery methods use natural gas to produce steam that is injected into the reservoir. As a result, one of the largest input costs in a SAGD or CSS operation is often the cost of natural gas.

#### *Light Oil / Heavy Oil Price Differentials*

Processing heavy oil and bitumen is more expensive than processing conventional light oil and it yields less high value products compared to refining light oil. Accordingly, producers of heavy oil and bitumen receive lower wellhead prices. The difference between prices for heavy oil and light oil (such as WTI oil with an API of 40°) is commonly referred to as the "light/heavy price differential". In order to calculate "light/heavy price differentials", the heavy oil prices are often derived from the Western Canada Select at Hardisty, Alberta or Lloyd Blend at Hardisty, Alberta published prices. Western Canada Select is comprised of Canadian bitumen and heavy oils blended with sweet synthetic and condensate diluents and Lloyd Blend is a heavy, sour crude oil.

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".

#### *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 can have a significant effect on the wellhead price of heavy oil. The most commonly used diluent for the production of heavy oil and bitumen in western Canada is condensate, but synthetic crude oil is also used.

#### *Accessibility to Transport*

Canada produces more heavy oil than it can refine, therefore, Canadian heavy oil is dependent on demand and refining capacity 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. There are currently proposals submitted to the US government to build heavy oil pipeline capacity from Hardisty, Alberta to the US Gulf Coast, a major heavy oil refining hub.

#### *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.

#### **Description of Properties**

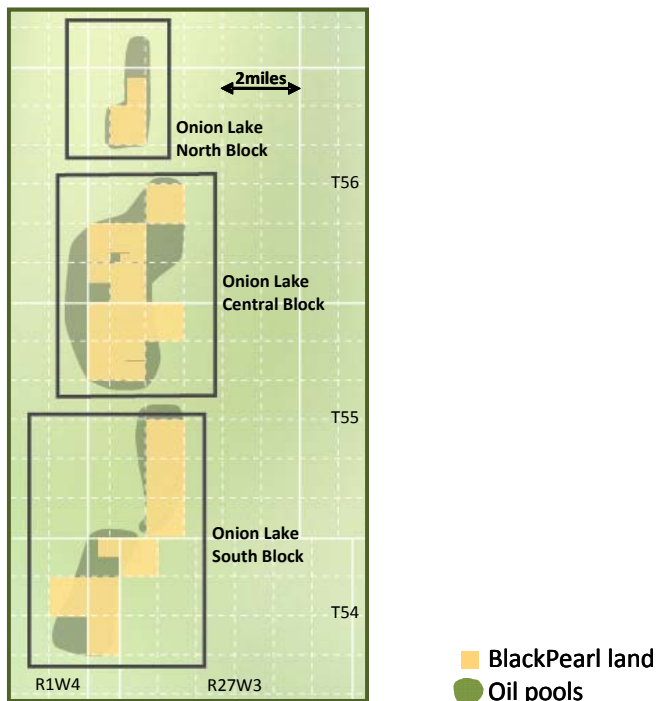
The following map outlines the location of our major assets as at December 31, 2010.



#### **Core Area Properties – Canada**

##### *Onion Lake Heavy Oil Project – Saskatchewan*

Onion Lake is a conventional heavy oil property that also has the potential for thermal development on a portion of the lands. BlackPearl originally acquired its interest in Onion Lake when it acquired Pan-Global Energy Ltd. in 2006. BlackPearl holds working interests, ranging from 87.5% to 100%, in approximately 18 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. The geological formation of interest is the Cretaceous Dina and Cummings sand formations at a depth of approximately 600 metres.



During 2010, BlackPearl produced an average of 5,038 boe/d at Onion Lake, primarily heavy oil, with an API of approximately 11°. This represented 72% of BlackPearl's total oil and gas production in 2010. At December 31, 2010 there were 93 heavy oil producing wells on the property.

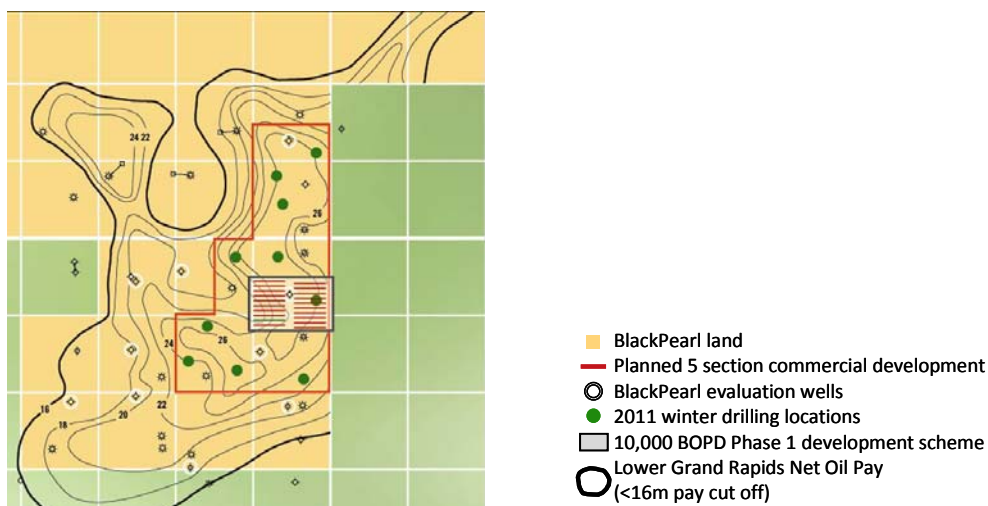
BlackPearl drilled 30 wells at Onion Lake in 2010. The Company has identified in excess of 200 additional conventional development drilling locations on the property. In addition to conventional drilling, due to reservoir thickness, a portion of the lands at Onion Lake are amenable to thermal development in the Dina formation. In 2009, BlackPearl undertook a two well thermal pilot on the property. The reservoir in this area of the Onion Lake lands is between 10 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 initiating SAGD development.

BlackPearl does not have any oil processing facilities at Onion Lake, and therefore production from the area is trucked to third party facilities or pipeline terminals.

At December 31, 2010, Sproule assigned proved plus probable reserves of 12.6 million barrels of oil equivalent to the Onion Lake area. In addition to proved and probable reserves, at December 31, 2010, Sproule has assigned 80 million barrels of contingent resource (best estimate) to the Onion Lake lands.

#### *Blackrod Heavy Oil Project – Alberta*

Blackrod is an in situ (SAGD) oil sands project located south of Fort McMurray, in the Athabasca oil sands 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. In 2010, BlackPearl acquired the remaining 20% in the Blackrod lands from Serrano Energy Ltd., for \$21 million. BlackPearl is the operator of the project.



The geological formation of interest is the Lower Grand Rapids at a depth of approximately 300 metres. The Grand Rapids formation is a shoreface sand deposit in a broad coastline setting which provides for a large, regional depositional environment. The Lower Grand Rapids reservoir sand ranges in thickness from 10 metres to 26 metres. Bitumen saturation is between 55% and 75%. There is currently no production from the Lower Grand Rapids formation in the Athabasca oil sands region.

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. The Company's SAGD recovery scheme was approved by the ERCB in late 2010. The pilot will consist of a single SAGD horizontal well pair, water source and disposal wells, observation wells, water monitoring wells and a central facility consisting of water treatment and steam generation equipment and other associated facilities. The information collected from the pilot operation will be used to submit a 40,000 barrel per day commercial development application expected to be filed in the next 18 months. The year-end contingent resource report (best estimate) prepared by Sproule indicates that the BlackPearl lands at Blackrod have the potential to support production of 70,000 barrels of oil per day. In order to access the approved lands, BlackPearl acquired an existing logging road in the area and upgraded the road to facilitate oil and gas operations. The road is approximately 31 kilometres and runs from Highway 63 to the central facility site. Non-potable water supplies to generate steam will come from the Grosmont formation. Emulsion (raw crude bitumen and water) produced from the pilot operations will be trucked from the central facility location to third party oil processing facilities and pipeline terminals.

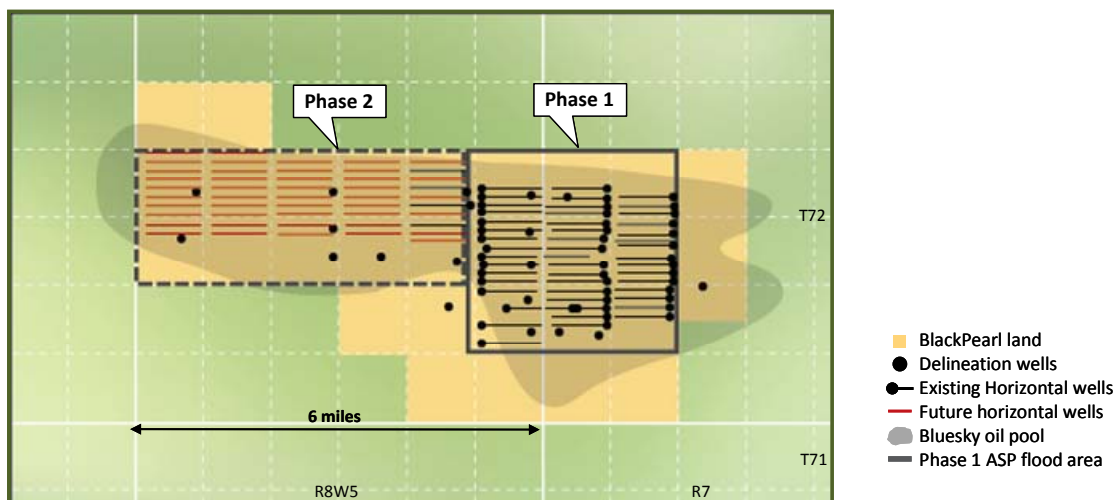
It is anticipated that steam injection will commence in the second quarter of 2011, and initial results from the pilot are expected six to twelve months after that.

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% of gross revenues until the project recovers all costs. After payout of project costs, the royalties are expected to 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. However, as at December 31, 2010, Sproule has attributed 619 million barrels of contingent resource (best estimate) to the Blackrod area lands.

#### *Mooney Heavy Oil Project – Alberta*

Mooney is a conventional heavy oil property located in north-central Alberta. BlackPearl has a 100% working interest in 79 sections in the Mooney field. The Mooney field produces mainly from the Bluesky sand formation, which is at a depth of approximately 900 metres. During 2010, oil and gas production averaged 1,008 boe/d net to BlackPearl. Four wells were drilled at Mooney in 2010.



BlackPearl has been operating the Mooney property for about five years. BlackPearl acquired its interest in the Mooney property when it acquired Atlas Energy Ltd. in 2006. The field was initially developed using primary production; however, the Company believes the performance of the Mooney field could 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. A three well polymer pilot, which operated for about 14 months, recovered approximately 18% of the oil in place. Primary recovery rates without ASP flooding would typically be 3–5%. 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. ERCB approval to proceed with phase one of our commercial polymer flood was received in late 2010 and field construction of the chemical and water handling facilities commenced immediately thereafter. Up to twenty two of the existing wells will be shut-in and converted to ASP injectors. Upgrades to the existing Mooney battery facility to handle the ASP/oil mix will occur in 2011. We expect to begin polymer injection in the second quarter of 2011, and response from the flood is expected to take six to twelve months. 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. The Company has received EOR royalty status for a portion of the Mooney field.

At December 31, 2010, Sproule assigned proved plus probable reserves of 10.7 million barrels of oil equivalent to the Mooney area, net to BlackPearl’s working interest. In addition, as at December 31, 2010 Sproule has assigned 40 million barrels of contingent resource (best estimate) to the Mooney lands.

#### Other Properties – Canada

The Company holds interests and has ongoing operations and production in several other areas of Saskatchewan and Alberta. These include John Lake, Druid, Fishing Lake and the 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 USA”), 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 its partner 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 production at San Miguel. No activities are planned on this property in 2011.

#### **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 and Promised Land in Montana. In 2010, the Company sold its interest in the Queen City gas field in Texas and a non-producing heavy oil field at Fiddler Creek in Montana. There is limited or no production from these areas and there are only minor evaluation plans contemplated for these lands in 2011.

#### **Employees**

The Company had 44 full time employees and two consultants as at December 31, 2010. The Company has also entered into arrangements with 27 contract operators to help manage and operate the Company's oil and gas properties.

### **INDUSTRY CONDITIONS**

#### **Government Regulation**

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition.

Although BlackPearl does not expect that these controls and regulations will affect the operations of BlackPearl in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and 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**

##### *Crude Oil*

Producers of crude oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on crude oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil. Oil may be exported from Canada

pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the National Energy Board (the "NEB"). Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

#### *Natural Gas*

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. 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 continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m<sup>3</sup>/day) are subject to an NEB order. Any natural gas exported under a contract of longer duration (to a maximum of 25 years) or in larger quantities requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market considerations.

#### *Natural Gas Liquids*

The price of natural gas liquids ("NGLs") sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are 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 criteria prescribed by the NEB and the Government of Canada. NGLs may be exported for a term of not more than one year in respect of propane and butane and not more than two years in respect of ethane – with all exports requiring an order of the NEB.

#### (a) The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the Canadian, United States and Mexican Governments came into effect on January 1, 1994. Under NAFTA, the Canadian government is free to determine whether exports of energy resources to the United States or Mexico should be allowed, provided that export restrictions do not: (1) reduce the proportion of energy resources exported relative to energy resources consumed domestically (with the most recent 36 month period proportion used as the basis for comparison); (2) impose a higher export price than domestic price (subject to an exception relating to certain voluntary measures that restrict the volume of exports); and (3) disrupt normal channels of supply.

NAFTA prohibits discriminatory border restrictions and export taxes and also prohibits the imposition of minimum or maximum export or import price requirements except with respect to the enforcement of countervailing and anti-dumping orders and undertakings. Discipline on regulators is addressed as the signatories to NAFTA agree to ensure that their regulatory bodies provide equitable implementation of regulatory measures and minimize the disruption of contractual arrangements.

#### **Land Tenure**

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal Governments. Lease terms vary in length. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Jurisdictions in Canada, including the provinces of Alberta, and Saskatchewan have legislation in place for mineral rights reversion to the Crown of formations that cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

## Royalties

### *General*

For crude oil, natural gas and related production from Federal or Provincial Government lands, the royalty regime is a significant factor in the profitability of our production. Crown royalties are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

### *Alberta*

The Alberta government implemented a new oil and gas royalty framework effective January 2009. The new framework established 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 framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

In November 2008, the Alberta government announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 metres, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5 percent to 30 percent. The election must be made prior to the end of the first calendar month in which the leased substance is produced.

In November 2008, in connection with the implementation and phase-in of the NRF, the Alberta Government announced a five-year program of "transitional" royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. Under the transitional royalty program, companies drilling new natural gas and conventional oil deep wells at depths between 1,000 meters and 3,500 meters (3,281 feet and 11,483 feet) spud after November 19, 2008 had a one-time option, on a well-by-well basis, to elect for the production from such wells to be subject to the transitional royalty rates or those provided for under the NRF. The option for producers to elect for transitional royalties in respect of qualifying deep wells ended on December 31, 2010. Any wells spudded on or after January 1, 2011 are subject to the royalty rates provided for under the ARF. Wells that are subject to transitional royalty rates will automatically revert to ARF rates on January 1, 2014.

The Deep Oil Exploration Program (the "**DOEP**") and the Natural Gas Deep Drilling Program (the "**NGDDP**") are two programs that became effective on January 1, 2009. These programs provide upfront royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first \$1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP has an escalating royalty credit in line with progressively deeper wells from \$625 per meter to a maximum of \$3,750 per meter and there are additional benefits for the deepest wells. Both the DOEP and the NGDDP are five year programs. Any wells spudded 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 the DOEP or the NGDDP after December 31, 2018. On May 27, 2010 the NGDDP was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres and including wells drilled into pools discovered prior to 1985, among other changes.

On March 3, 2009, the Alberta government announced a three-point incentive program. This incentive program includes a drilling royalty credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, providing a \$200-per-metre-drilled royalty credit to companies on a sliding scale based on their production levels from the previous year. There is

also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2010 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. As of June 25, 2009, the Alberta government has extended these two programs to March 31, 2011. The Province of Alberta will also invest \$30 million 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.

On March 11, 2010, the Alberta government announced its intention to adjust royalty rates effective January 1, 2011. This adjustment includes making the incentive program royalty rate of 5% on new natural gas and conventional oil wells a permanent feature of the royalty system with the time and volume limits discussed above. The maximum royalty rate will be reduced from the current levels of 50% to 40% for conventional oil and to 36% for natural gas. The transitional royalty framework for oil and gas will continue until December 31, 2013 as announced and no new wells will be allowed to select transitional royalty rates effective January 1, 2011; wells that have selected the transitional royalty rates will be allowed to switch to the new rates effective January 1, 2011. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. The implementation of the royalty adjustments is subject to certain risks and uncertainties, including changes to existing legislation and the regulation and development of proprietary software to support the calculation and collection of royalties.

The Alberta oil sands royalty payable is based on price-sensitive royalty rates. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. "Payout" generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. When a project reaches payout, its cumulative revenue equals or exceeds its cumulative costs. Costs include specified allowed capital and operating costs pursuant to the Oil Sands Allowed Costs (Ministerial) Regulation. 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 that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above \$55 per barrel, to a maximum of 9% when the WTI crude oil price is \$120 per barrel or higher. The royalty payable for post-payout projects is the greater of the gross revenue royalty based on the gross revenue royalty rate or the net revenue royalty based on the net revenue royalty rate. The net royalty rate starts at 25% and increases for every dollar the WTI crude oil price is above \$55 per barrel to a maximum of 40% when the WTI crude oil price \$120 per barrel or higher.

As the resource owner, the Government of Alberta is entitled to take its royalty share of bitumen production in kind, as it does currently for conventional oil production. The Government of Alberta is currently considering having a portion of its bitumen royalty in-kind volumes commercially upgraded to higher value products in the province.

In conjunction with the release of the new royalty curves on May 27, 2010 the Alberta government also announced its Emerging Resources and Technology Initiative intended to accelerate new technologies and encourage the development of unconventional resources. Among other initiatives, the following changes were announced:

- Coalbed Methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 million cubic feet of production, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty of 5% for 18 producing months up to 500 million cubic feet of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resources and Technology Initiative will be reviewed in 2014 and the Alberta government has committed to provide industry three years notice if it intends to discontinue the program.

### ***Saskatchewan***

Crown royalty rates are sensitive to the individual productivity of each natural gas well. The rates are applied to the respective portions of each classification of gas ("fourth tier gas", "third tier gas", "new gas" and "old gas") produced from a well.

Each month, the royalty rates are adjusted based on the level of the Provincial Average Gas Price ("PGP") established by the Province monthly. The PGP represents the weighted average fieldgate price (expressed in  $\$/10^3\text{m}^3$ ) received by producers during the month for the sale of all gas subject to royalty. Crown royalty on the production volume is calculated on each individual well using the applicable royalty rate to the volume of gas produced by each well on a monthly basis.

At the present time, the operator must elect to use either the PGP or 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 ( $\$/10^3\text{m}^3$ ) 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. On June 14, 2010 the Province of Saskatchewan announced that it will eliminate the option of using the OGP for purposes of valuing the Crown's royalty share of the production volume from each well commencing from the fall of 2011, and will require use of the PGP. The proposed changes may require further consultation and there may be modifications introduced prior to the implementation of such changes.

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of the oil determined monthly by the provincial government. Each month, royalty rates are adjusted based on the level of the reference price established by the Province for each type of oil. For Crown royalty purposes, crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". There are separate reference prices established for each type of oil which represent the average wellhead price (in  $\$/\text{m}^3$ ) received by producers during the month for sales of that oil type in Saskatchewan.

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.

A separate cost sensitive royalty structure applies to incremental production from enhanced oil recovery projects, which incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.

The Government of Saskatchewan has introduced a number of oil and natural gas royalty reduction and credit incentive programs to encourage oil and gas exploration and development in Saskatchewan. Such programs include:

- An incentive volume for exploratory gas wells drilled on or after October 1, 2002 and for horizontal gas wells drilled on or after June 1, 2010 and before April 1, 2013. A lower royalty rate applies (2.5%) to natural gas produced from such wells up to 25 million cubic metres.
- A cost sensitive royalty structure that applies to incremental production from enhanced oil recovery projects that are not Waterflood projects. There are different royalty structures for projects that commenced operation prior to April 1, 2005 and for those that commence operation on or after April 1, 2005. There is also another royalty structure that applies to incremental oil produced from new or expanded Waterflood projects that are implemented on or after October 1, 2002. Each of these royalty structures incorporates lower royalty and freehold production tax rates before the project reaches payout of investment and operating expenditures.
- Different incentive volumes for Deep Development Vertical Oil Well, Exploratory Vertical Oil Well, Horizontal Oil Well and Deep Horizontal Oil Well drilled after October 1, 2002. A lower royalty rate applies to oil produced from such wells up to and including the incentive volumes specified for each such well.
- Individual oil wells or a group of them that are either producing conventional oil at an average water-cut of 95% or greater in the twelve calendar months preceding an application under the program or have been shut-in or suspended for twelve or more consecutive calendar months prior to making investments under the program and produced at an average water-cut of 95% or greater during the three producing months immediately preceding the shut-in or suspension qualify for a royalty incentive that is designed to extend the producing lives and improve the recovery rate of high water-cut oil wells. Oil produced from a well that has an average water-cut of 50% or greater that is part of a group of oil wells that produce at an average water-cut of 95% or greater and benefit from the same qualifying investment also qualifies under this incentive program.

Saskatchewan has introduced an orphan oil and gas well and facility program, funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

## Environmental Regulation

As an operator of oil and natural gas properties in Canada, we are subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

We currently operate or lease, and have in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future. We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which we operate. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

## Greenhouse Gases and Industrial Air Pollutants

### *Kyoto Protocol and Copenhagen Accord*

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. However, the Government of Canada has concluded that Canada will not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions.

From December 6 to 18, 2009, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review of implementation of its stated goals before 2016.

### **Federal**

The Government of Canada previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "**Regulatory Framework**"), for regulating GHG emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. In 2009, the Government of Canada announced its commitment to work with the provincial governments to implement a North American-wide 'cap and trade' system for GHG emissions, in cooperation with the United States. On January 30, 2010, the

Government of Canada announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with U.S. policy.

The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether either federal GHG regulations or an integrated North American 'cap and trade' system will or will not be implemented, or what obligations might be imposed under any such system. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on BlackPearl's operations cannot be determined at this time.

### **Alberta**

Alberta currently 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, GHG emissions of 100,000 tonnes or more from a facility in any year must be reported to Alberta Environment. Alberta Environment has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tonnes of GHG emissions annually. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000, or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached.

There are three ways to comply with the SGER reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta-based emission offset credits and/or emission performance credits; or (iii) purchase of fund credits at a cost of \$15 per tonne of GHG emissions, with the proceeds going to the Government of Alberta's Climate Change and Emissions Management Fund. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually. The Government of Alberta has previously announced in its 2008 Provincial Energy Strategy that it may modify the SGER towards stricter standards.

In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

### **Saskatchewan**

*The Management and Reduction of Greenhouse Gases Act* received Royal Assent in the Province of Saskatchewan on May 20, 2010. However, this Act is still awaiting proclamation. The new legislation will establish a provincial plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Province has indicated that it intends to enter into an equivalency agreement with the federal government to achieve equivalent environmental outcomes under provincial regulation. A draft of the proposed regulations to accompany the Act calls for a reduction of emissions by 20% below 2006 levels by 2020.

## **RISK FACTORS**

The Company is exposed to a number of risks inherent in exploring for, developing and producing heavy oil, bitumen 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*

The Company's revenues, cash flow, results of operations and financial condition are dependent upon, among other things, the price it receives for the heavy oil, bitumen, and bitumen blend that it sells, and the price that it receives for these products is closely correlated to the price of crude oil. Historically, crude oil markets have been volatile and are likely to continue to be volatile in the future. These fluctuations in price are in response to factors including, but not limited to, supply and demand for crude oil and natural gas, market uncertainty, world economic conditions, government regulation, political instability, availability of refining capacity and transportation infrastructure, weather conditions and the prices of alternative forms of energy, all of which are generally beyond the control of the Company.

Any extended decline in the price of crude oil could result in the delay or cancellation of future drilling programs or construction projects. Any such actions could have a material adverse effect on BlackPearl's business, financial condition, results of operations and cash flows.

There is no generally recognized approach to determine the constant price for bitumen because the bitumen market is not yet mature and there are no published reference prices for bitumen. To price bitumen, marketers apply formulas that take as a reference point the prices published for crude oil of particular qualities such as Edmonton Light, Western Canadian Select, Lloydminster Blend, or the more internationally known WTI. The price of heavy oil and bitumen fluctuates widely during the course of a year, with the lowest prices typically occurring at the end of the calendar year because of decreased seasonal demand for asphalt and other bitumen-derived products coupled with higher prices for diluents added to facilitate pipeline transportation of bitumen.

Over 90% of BlackPearl's production is from heavy oil. The market prices for heavy oil (which includes bitumen blends) are lower than the established market indices for light or medium grades of oil, due principally to diluent prices and the higher transportation and refining costs associated with heavy oil. Also, the market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in the heavy oil differentials could have an adverse effect on the Company's business, financial condition, results of operations and cash flows.

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.

### *Volatility of Commodity Inputs*

Natural gas production is not a significant component of the Company's total current production, therefore changes in gas prices do not currently materially affect the Company. However, as the thermal projects at Blackrod and Onion Lake reach the production stage, natural gas is expected to be used to generate steam and changes in natural gas prices is expected to affect the Company's cost structure, and could have a material adverse effect on BlackPearl's business, financial condition, results of operations and cash flows.

In order to meet pipeline specifications, heavy oil and bitumen is usually blended with a lighter hydrocarbon (commonly referred to as diluent) to increase its flow characteristics. The cost of diluent is highly correlated to crude oil prices. As a result, the Company expects to be able to offset a portion or all of the increase in its costs associated with an increase in diluent prices with an increase in revenue that results from higher oil prices. However, in the event this correlation changes, the Company's results of operations and financial condition could be adversely affected.

### *Access to Capital*

BlackPearl has positive working capital and no long term debt as of December 31, 2010; however, the Company 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. In particular, the thermal projects at Blackrod and Onion Lake will require substantial capital to fully develop the properties. Presently, the major source of funds available to the Company is the issuance of additional equity or debt, and cash flow from operations. The worldwide economic downturn of 2008 and 2009 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. There can be no assurance that the Company will be successful in its efforts to arrange additional financing on terms satisfactory to the Company or at all. If the Company obtains additional financing by the issuance of shares from treasury, control of the Company may be affected and, depending on the issue price of such shares,

existing shareholders may suffer dilution. The inability of BlackPearl to access sufficient capital for its operations could adversely affect the expected growth and development of the Company's business.

#### *Uncertainty of Reserve and Contingent Resource Estimates*

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and quantities of contingent resources and future net revenues to be derived therefrom, including many factors beyond the control of the Company. The reserves, contingent resources and future net cash flow information set forth herein represent estimates only. While the reserves, contingent resources and future net cash flow information from the Company's properties have been independently evaluated by Sproule in the Sproule Report, these evaluations include a number of assumptions, including, without limitation, such factors as initial production rates, production decline rates, ultimate recovery of reserves and contingent resources, timing and amount of capital expenditures, marketability of production, future prices of oil, bitumen and natural gas, operating costs, well abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

The present value of the Company's estimated future net revenue disclosed in this Annual Information Form or the Sproule Report should not be construed as the fair market value of the Company's reserves and contingent resources, as applicable.

BlackPearl has no SAGD production history from its planned SAGD thermal projects at Blackrod and Onion Lake. Estimates with respect to reserves and contingent resources that may be developed and produced in the future are often based upon volumetric calculations, and upon analogy to similar types of reserves and contingent resources, rather than those based on actual production history. Subsequent evaluation of the same reserves and contingent resources based upon production history will result in variations, which may be material, in the estimated reserves or contingent resources.

Reserves and contingent resources estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of heavy oil, bitumen and natural gas prices may render the recovery of the reserves or contingent resources uneconomic.

A significant portion of BlackPearl's reserves and contingent resources are non-producing or undeveloped. The reserves and contingent resources may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. In addition, not all of the Company's undeveloped reserves and contingent resources may be ultimately produced at the time period BlackPearl has planned, at the costs the Company has budgeted, or at all.

The estimates of reserves, contingent resources and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves, contingent resources and future net revenue for all properties due to the effects of aggregation.

#### *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 business, financial condition, results of operations and cash flows.

In general, the operations of BlackPearl require licenses and permits from various governmental authorities. The construction and operation of the thermal projects at Blackrod and Onion Lake will require various environmental and other regulatory approvals. There is 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. In addition, once permits are issued there is no assurance that the approvals will not be repealed, or renewed, or that they will contain terms and conditions which make the Company's projects and operations uneconomic or cause the Company to significantly alter its projects and operations.

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 direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our 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 our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance 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 may materially adversely affect BlackPearl'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 BlackPearl or by consumers of BlackPearl's products. The imposition of such measures might negatively affect BlackPearl's costs and prices for BlackPearl's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from BlackPearl's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

We believe that we are in material compliance with applicable environmental legislation and are committed to continued compliance. We believe that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and we anticipate making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

### *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 BlackPearl is able to explore and operate on Onion Lake treaty lands.

### *Operational Risks*

The Company's oil and natural gas 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. The Company attempts to mitigate 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. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

### *Capital Cost Over-runs*

Oil sands projects require a substantial amount of capital to construct and place on production. Due to the number of projects built and planned to be built, the Athabasca oil sands region has seen inflationary pressure on labour rates as well as costs for goods and services on these large projects. While the economic downturn in 2008 and 2009 has reduced some of these cost pressures, as oil prices increase and the North American and world economies improve, demand for labour and goods and

services could increase in the area which may result in higher costs for these oil sands projects. The planned Blackrod project is in the Athabasca oil sands region and therefore the project could be negatively impacted by higher capital costs. The Onion Lake thermal project, while not in the Athabasca oil sands region, may also be impacted by increased oil sands activity in western Canada. Higher capital costs could result in project delays or postponement which could materially adversely effect BlackPearl's business, financial condition, results of operations and cash flows.

#### *Foreign Exchange Risk*

Most of BlackPearl's revenues are based on the US dollar, since revenues from the sale of heavy oil and bitumen is generally referenced to a price denominated in US dollars, and BlackPearl incurs most of its operating and other costs in Canadian dollars. As a result, BlackPearl is impacted by exchange rate fluctuations between the US dollar and the Canadian dollar and any strengthening of the Canadian dollar relative to the US dollar could negatively impact revenues and cash flow.

#### *Diluent Supply*

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

#### *Competition*

The Canadian and international petroleum industry is highly competitive in all respects, including, without limitation, the exploration for, and the development of, new sources of supply, the acquisition of crude oil, natural gas and oil sands leases, licenses and concessions and the distribution and marketing of petroleum products. The Company competes with other producers of bitumen, synthetic crude oil blends and conventional crude oil. Some of these producers have lower operating costs than BlackPearl and many of them have greater resources to source, attract and retain the personnel, materials and services that the Company requires to conduct its operations. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of other companies have announced plans to enter the heavy oil or oil sands business or expand existing operations. Expansion of existing operations and development of new projects could significantly increase the supply of heavy oil and bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of heavy oil and bitumen and accordingly, the Company's results of operations, financial condition and prospects. In addition, expansion of existing operations and development of new projects could materially increase the costs of inputs such as natural gas, diluent, labour, equipment, materials or services, which, in turn, may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

#### *SAGD Bitumen Recovery Process*

The recovery of bitumen using SAGD processes is subject to uncertainty. Current SAGD technologies for in situ extraction of bitumen are energy intensive, requiring significant consumption of natural gas or other fuels to produce steam for use in the recovery process. There can be no assurance that the Company's operations will produce bitumen at the expected levels or on schedule. The amount of steam required in the production process can vary and impact costs significantly. The quality and performance of the bitumen reservoir can also impact the Company's steam-oil ratio and the timing and levels of production using this technology. Should the Company encounter adverse reservoir conditions, bitumen recovery levels achieved by the Company using SAGD processes may be negatively impacted.

#### *Alkali Surfactant Polymer (ASP) Recovery Process*

The recovery of heavy oil using an ASP flood is subject to uncertainty. Alkali surfactant is added to a polymer flood and is intended to dislodge oil trapped in pore spaces of the reservoir. The polymer increases the viscosity of the water to enhance the sweep of the reservoir. The process is subject to risks that include premature water breakthrough, poor reservoir sweep efficiency and adverse chemical reactions in the reservoir. These risks could result in production levels and recovery rates less than expected. In addition, if more chemicals are required to be injected than was anticipated, it could render the project uneconomic.

### *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 the downturn in economic conditions during 2008 and 2009 and the contraction in the availability of credit, the likelihood of a third party failing to meet its obligations has increased.

### *Expiration of Leases, Licenses or Permits*

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

### *Reliance on Third Parties*

The Company's core projects at Onion Lake, Blackrod and Mooney as well as the non-core assets of the Company will depend on certain infrastructure owned and operated by third parties, including, without limitation, pipelines for the transportation of heavy oil and bitumen to market, natural gas, disposal pipelines and electrical grid transmission lines for the sale of electricity to the Company.

Currently, all of BlackPearl's heavy oil production is trucked from the lease to a sales point. The ability to deliver oil to market is dependent on, among other things, access to trucks and drivers, accidents, weather delay and general road conditions. The Company is also dependent on third parties to provide other services such as drilling and servicing wells.

The failure of any of these third parties to supply goods and services on a timely basis and on acceptable commercial terms will adversely effect the Company's business, financial condition, results of operations and cash flows.

### *Royalty Regimes*

The Governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which they own the mineral rights. At Onion Lake, operations are conducted on the Onion Lake First Nation reserve, and the Company pays royalties to Indian Oil and Gas Canada based on production on reserve lands. The royalty paid at Onion Lake is equivalent to the prevailing Government of Saskatchewan royalty rate (without reference to third tier, fourth tier, enhanced oil recovery royalties, holidays or other special incentives).

The Government of Alberta has publicly indicated that it intends to review its existing royalty regime from time to time. There can be no assurance that the federal government and the Governments of Alberta or Saskatchewan will not adopt a new royalty regime which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged.

An increase in royalties would reduce the Company's earnings and could make future capital investments or the Company's operations uneconomic.

### *Abandonment and Reclamation Costs*

Estimates of the Company's abandonment and reclamation costs will be a function of regulatory requirements existing at the time that the estimates are made, which are subject to change in the future. In addition, the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. Consequently, the estimates may or may not reflect these future costs. The Company has not established a specific fund to provide for the payment of future abandonment and reclamation costs.

### *Management Estimates and Assumptions*

In preparing consolidated financial statements estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated

based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management's assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

#### *Availability of Drilling Equipment and Access*

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

#### *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 effect 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.

It is likely that other oil sands projects will proceed at the same time as the Blackrod and Onion Lake thermal projects and the Company will compete with these other projects for experienced employees, which may result in increased compensation costs or the inability to hire qualified personnel.

#### *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.

#### *Geo-Political Risks*

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

In addition, the long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. The possibility that infrastructure and other facilities, such as pipelines, terminals and refineries, may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks have resulted in, and are expected to continue to result in, increased costs to the Company's business. Furthermore, any interruption in the services provided by infrastructure on which the Company relies as a result of terrorist attack would have a material adverse effect on the Company's results of operations, financial condition and prospects.

#### *Insurance Risks*

The Company's property and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Company.

### *Litigation Risk*

In the normal course of the Company's operations, it may become involved in, named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's business, financial condition, results of operations and cash flows. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

### *Conflicts of Interest*

Some of the directors and officers of the Company are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Company. 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 seek to acquire additional companies or assets in the oil and natural gas industry. The acquisition of companies or assets is subject to substantial risks, including the failure to identify material problems during due diligence, the risk of over-paying for assets, and the inability to arrange financing for an acquisition as may be required or desired. Furthermore, 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. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

## **STATEMENT OF RESERVES AND CONTINGENT RESOURCES DATA AND OTHER OIL AND GAS INFORMATION**

Sproule has evaluated the proved plus probable heavy oil, bitumen and natural gas reserves and contingent resources of the Company as at December 31, 2010 (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, 2010 and a preparation date of January 18, 2011.

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 (see "Risk Factors").

All of BlackPearl's proved plus probable oil and gas reserves are located within Canada, specifically Alberta and Saskatchewan.

Sproule's "Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor" in Form 51-102F2 and "Report on Resources Data by Independent Qualified Reserves Evaluator or Auditor" are attached as Schedule A to this Annual Information Form. The Company's "Report of Management and Directors on Oil and Gas Disclosure" in Form 51-101F3 is attached as Schedule B to this Annual Information Form.

**SUMMARY OF OIL AND GAS RESERVES  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

Reserve Category	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
<b>Proved</b>								
Developed Producing	0.8	0.8	4,452.0	3,357.7	1,846.0	1,765.0	6.6	4.4
Developed Non-Producing	0.0	0.0	360.4	297.4	13.0	10.0	0.0	0.0
Undeveloped	0.0	0.0	6,526.2	4,871.7	310.0	286.0	0.7	0.5
<b>Total Proved</b>	<b>0.8</b>	<b>0.8</b>	<b>11,338.6</b>	<b>8,526.7</b>	<b>2,170.0</b>	<b>2,060.0</b>	<b>7.3</b>	<b>4.9</b>
Probable	0.2	0.2	12,908.3	8,982.1	1,306.0	1,144.0	3.6	2.3
<b>Total Proved Plus Probable</b>	<b>1.1</b>	<b>1.0</b>	<b>24,246.9</b>	<b>17,508.9</b>	<b>3,476.0</b>	<b>3,204.0</b>	<b>11.0</b>	<b>7.2</b>

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

Reserves Category	Before Income Taxes Discounted at (%/Year)							Before Tax Unit Value <sup>1</sup> 10%/yr (\$/boe)
	0 (M\$)	5 (M\$)	8 (M\$)	10 (M\$)	12 (M\$)	15 (M\$)	20 (M\$)	
	<b>Proved</b>							
Developed Producing	173,864	163,756	158,387	155,058	151,909	147,495	140,858	42.40
Developed Non-Producing	7,812	6,668	6,093	5,747	5,429	4,995	4,371	19.22
Undeveloped	157,468	130,379	117,259	109,511	102,439	92,919	79,422	22.26
<b>Total Proved</b>	<b>339,145</b>	<b>300,803</b>	<b>281,739</b>	<b>270,317</b>	<b>259,778</b>	<b>245,409</b>	<b>224,652</b>	<b>30.46</b>
Probable	397,635	278,904	234,469	211,170	191,516	167,172	136,221	23.02
<b>Total Proved Plus Probable</b>	<b>736,780</b>	<b>579,707</b>	<b>516,209</b>	<b>481,487</b>	<b>451,293</b>	<b>412,581</b>	<b>360,874</b>	<b>26.67</b>

Reserves Category	After Income Taxes Discounted at (%/Year)						
	0 (M\$)	5 (M\$)	8 (M\$)	10 (M\$)	12 (M\$)	15 (M\$)	20 (M\$)
<b>Proved</b>							
Developed Producing	173,864	163,756	158,387	155,058	151,909	147,495	140,858
Developed Non-Producing	7,812	6,668	6,093	5,747	5,429	4,995	4,371
Undeveloped	149,518	123,479	110,900	103,481	96,701	87,614	74,728
<b>Total Proved</b>	<b>331,194</b>	<b>293,903</b>	<b>275,380</b>	<b>264,286</b>	<b>254,037</b>	<b>240,104</b>	<b>219,958</b>
Probable	306,959	213,017	177,803	159,357	143,887	124,629	100,351
<b>Total Proved Plus Probable</b>	<b>638,152</b>	<b>506,920</b>	<b>453,183</b>	<b>423,643</b>	<b>397,845</b>	<b>364,732</b>	<b>320,308</b>

Notes:

(1) Unit values are based on net reserve volumes

**TOTAL FUTURE NET REVENUE (undiscounted)  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

Reserves Category	Revenue	Royalties	Operating Costs	Development 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\$)
Proved	851,834	199,926	179,886	104,516	28,362	339,145	7,951	331,194
Proved Plus Probable	1,893,895	496,247	447,054	172,567	41,248	736,780	98,628	638,152

**NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)	Unit Value <sup>2</sup> Before Income Taxes (Discounted at 10%/Year) (\$/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0.00
	Heavy Oil (including solution gas and associated by-products)	266,744	31.00
	Natural Gas (including associated by-products)	3,573	13.21
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0.00
	Heavy Oil (including solution gas and associated by-products)	476,613	26.90
	Natural Gas (including associated by-products)	4,874	14.59

Notes:

- (1) Includes Corporate GCA, if applicable
- (2) 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 and Contingent Resources Data and Other Oil and Gas 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 to the extent necessary in developing the reserves;
  - (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, treaters, 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 defence, 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, reserves and contingent resources, 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 and contingent resources, 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 of its gross wells; 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.

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

Each of the reserve categories (proved, probable and possible) 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;
- (b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- (c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates 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 price forecasts that formed the basis for the revenue projections and net present value estimates in the Sproule Report were based on Sproule's January 1, 2011 pricing models. A summary of selected price forecasts used by Sproule is set forth below.

#### SUMMARY OF PRICING USED IN PREPARATION OF RESERVES AND CONTINGENT RESOURCES DATA AS AT DECEMBER 31, 2010 FORECAST PRICES AND COSTS

Year	Edmonton		Hardisty		Pentanes		Inflation Rate <sup>2</sup> (%/Yr)	Exchange Rate <sup>3</sup> (\$US/\$Cdn)
	WTI	Par	Lloydblend	Natural Gas <sup>1</sup>	Plus	Butanes		
	Cushing	Price	20.5°	AECO Gas	FOB	F.O.B.		
	Oklahoma	40° API	API	Prices	Field Gate	Field Gate		
	(\$US/bbl)	(\$Cdn/bbl)	(\$Cdn/bbl)	(\$Cdn/MMBtu)	(\$Cdn/bbl)	(\$Cdn/bbl)		
<b>Historical</b>								
2006	66.09	73.30	50.30	7.16	75.03	59.32	n/a	0.882
2007	72.27	77.06	51.93	6.65	77.33	63.71	n/a	0.935
2008	99.59	102.85	82.58	8.15	104.70	75.09	n/a	0.943
2009	61.63	66.20	58.49	4.19	68.13	47.07	n/a	0.880
2010	79.43	77.81	67.16	4.16	84.21	57.04	n/a	0.971
<b>Forecast</b>								
2011	88.40	93.08	80.04	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	80.71	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	78.48	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	76.70	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	77.86	6.69	97.24	63.69	1.5	0.932
2016	91.57	96.38	79.03	6.80	98.71	64.65	1.5	0.932
2017	92.94	97.84	80.23	6.91	100.20	65.63	1.5	0.932
2018	94.34	99.32	81.44	7.02	101.71	66.62	1.5	0.932
2019	95.75	100.81	82.67	7.14	103.25	67.63	1.5	0.932
2020	97.19	102.34	83.92	7.26	104.81	68.65	1.5	0.932

Thereafter Escalation Rate of 1.5%

#### Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) Inflation rates used in forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.
- (4) None of the Company's future production is subject to a fixed or contractually committed price.
- (5) The Company's weighted average wellhead price in 2010 was \$58.86 per bbl for heavy oil/bitumen/NGLs and \$4.14 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, 2009 to December 31, 2010.

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

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
Dec. 31, 2009	110	44	154	10,621	11,744	22,365	4,914	1,659	6,572	23	7	30
Extensions	0	0	0	3,242	1,624	4,866	36	10	46	0	0	0
Improved Recovery	0	0	0	128	31	159	0	0	0	0	0	0
Technical Revisions	0	0	0	1,844	41	1,885	773	407	1,181	(2)	0	(2)
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	154	253	407	43	15	58	0	0	0
Dispositions	(103)	(43)	(146)	(2,377)	(898)	(3,274)	(2,327)	(782)	(3,110)	(10)	(3)	(13)
Economic Factors	0	(1)	(0)	42	113	155	(8)	(2)	(10)	0	0	0
Production	(7)	0	(7)	(2,316)	0	(2,316)	(1,261)	0	(1,261)	(4)	0	(4)
Dec. 31, 2010	1	0	1	11,339	12,908	24,247	2,170	1,307	3,477	7	4	11

#### 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		Natural Gas Liquids	
	1 <sup>st</sup> attributed Gross (Mbbbl)	Cumulative Gross (Mbbbl)	1 <sup>st</sup> attributed Gross (Mbbbl)	Cumulative Gross (Mbbbl)	1 <sup>st</sup> attributed Gross (MMcf)	Cumulative Gross (MMcf)	1 <sup>st</sup> attributed Gross (Mbbbl)	Cumulative Gross (Mbbbl)
<b>Proved Undeveloped</b>								
2008	4.0	4.0	0.0	3,375.0	1.0	579.0	0.0	0.0
2009	5.5	5.5	3,819.0	6,967.4	2.0	240.0	0.5	0.5
2010	0.0	0.0	2,401.2	6,526.2	0.0	310.0	0.0	0.7
<b>Probable Undeveloped</b>								
2008	2.0	50.0	0.0	8,921.0	1.0	1,429.0	0.0	0.0
2009	4.0	4.0	2,396.0	8,579.0	1.0	374.0	0.9	0.9
2010	0.0	0.0	766.9	9,932.3	159.0	800.0	0.4	1.8

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 148 future drilling locations. In 2011, we have plans to drill approximately 80 of these locations and we will likely drill an additional 50 of these locations in 2012. The high level of undeveloped reserves relative to developed reserves at Onion Lake is due to the relative 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, the majority of the undeveloped reserves were assigned based upon the ongoing conversion of a large portion of the field to an alkali surfactant polymer (ASP) flood. It is expected that the construction of the commercial ASP flood facility will be finished and ASP injection will commence in Q2 2011. Given the expected injection time before initial flood response and the time to analyze the results, it is not expected that follow up phases of the ASP flood would be implemented prior to year-end 2012. 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 budget priorities. 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. See "Risk Factors".

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.

	Total Proved (\$M)	Total Proved Plus Probable (\$M)
2011	64,094	88,729
2012	32,069	53,176
2013	7,696	28,991
2014	507	1,521
2015	74	74
Remainder	75	75
<b>Total for all years undiscounted</b>	<b>104,516</b>	<b>172,567</b>
<b>Total for all years discounted at 10% per year</b>	<b>96,126</b>	<b>154,779</b>

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 Company's Board of Directors 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.

### CONTINGENT RESOURCES

The following tables summarize certain information contained in the contingent resource evaluations prepared by Sproule as of December 31, 2010. The reports were independently prepared in accordance with definitions, standards and procedures contained in the COGE Handbook, and are based on Sproule's January 1, 2011 pricing models (see "Pricing Assumptions"). The following tables do not include the proved and probable reserves assigned by Sproule as at December 31, 2010.

It should not be assumed that the estimates of recovery, production, and net revenue presented in the tables below represent the fair market value of the Company's contingent resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material. The recovery and production estimates of the Company's contingent resources provided herein are only estimates and there is no guarantee that the estimated contingent resources will be recovered or produced. Actual contingent resources may be greater than or less than the estimates provided here. The contingencies which currently prevent the classification of these contingent resources as reserves consist of further delineation drilling, regulatory applications, preparation of firm development plans and corporate approvals to proceed with development. Once all regulatory and corporate approvals are received and any other contingencies are removed, the resources may then be reclassified as reserves. There is no certainty that it will be commercially viable for the Company to produce any portion of the contingent resources on any of its properties.

Project	Gross Heavy Oil//Bitumen	Net Present Values of Future Net Revenue <u>Before Income Taxes</u> as of December 31, 2010 Contingent Resources Discounted at						
		0%	5%	8%	10%	12%	15%	20%
	(MMboe)	(\$million)						
<b>Blackrod</b>								
Low Estimate <sup>3</sup>	552	11,984	4,307	2,495	1,776	1,287	816	404
Best Estimate <sup>2</sup>	619	14,882	5,041	2,854	2,011	1,447	912	453
High Estimate <sup>4</sup>	686	18,137	5,800	3,219	2,250	1,611	1,015	509
<b>Onion Lake</b>								
Low Estimate <sup>3</sup>	71	2,753	1,300	870	675	529	371	206
Best Estimate <sup>2</sup>	80	3,307	1,551	1,044	817	647	465	276
High Estimate <sup>4</sup>	87	3,576	1,803	1,253	999	804	591	364
<b>Mooney</b>								
Low Estimate <sup>3</sup>	42	1,028	511	360	290	236	175	109
Best Estimate <sup>2</sup>	40	998	474	325	257	205	148	87
High Estimate <sup>4</sup>	48	1,243	607	425	341	277	206	130

Project	Gross Heavy Oil//Bitumen	Net Present Values of Future Net Revenue <u>After Income Taxes</u> as of December 31, 2010						
		Contingent Resources Discounted at						
		0%	5%	8%	10%	12%	15%	20%
	(MMboe)	(\$million)						
<b>Blackrod</b>								
Low Estimate <sup>3</sup>	552	8,952	3,147	1,791	1,258	897	552	255
Best Estimate <sup>2</sup>	619	11,132	3,700	2,065	1,438	1,020	627	294
High Estimate <sup>4</sup>	686	13,573	4,273	2,342	1,621	1,147	707	338
<b>Onion Lake</b>								
Low Estimate <sup>3</sup>	71	2,009	934	615	470	362	244	121
Best Estimate <sup>2</sup>	80	2,414	1,117	742	574	449	314	173
High Estimate <sup>4</sup>	87	2,610	1,300	893	705	561	402	234
<b>Mooney</b>								
Low Estimate <sup>3</sup>	42	771	379	263	210	169	123	73
Best Estimate <sup>2</sup>	40	749	352	239	188	148	105	59
High Estimate <sup>4</sup>	48	932	452	314	251	202	149	91

Notes:

- (1) **Contingent resources** are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.
- (2) **Best estimate** (P50) is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.
- (3) **Low estimate** (P90) is a classification of estimated resources described in the COGE Handbook as being considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the Low Estimate. If probabilistic methods are used, there should be a 90% probability that the quantities actually recovered will equal or exceed the Low Estimate.
- (4) **High estimate** (P10) is a classification of estimate resources described in the COGE Handbook as being considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the High Estimate. If probabilistic methods are used, there should be a 10% probability that the quantities actually recovered will equal or exceed the High Estimate.
- (5) **Gross** means the Company's working interest share in the contingent resources of bitumen and heavy oil before deducting royalties. The Company has a 100% working interest at Blackrod and Mooney, and a 87.5% working interest at Onion Lake.
- (6) The amounts included in these tables do not include the volume and value of BlackPearl's proved and probable reserves previously assigned by Sproule to these properties.

## OTHER OIL AND GAS INFORMATION

### OIL AND GAS WELLS

The following table sets out BlackPearl's gross and net interests in oil and natural gas wells in which it has a working interest as at December 31, 2010:

	Oil wells				Gas wells			
	Producing		Non-producing		Producing		Non-producing	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Canada								
Alberta	69	56	254	220	31	19	275	195
Saskatchewan	101	88	106	98	-	-	-	-
US	-	-	18	12	-	-	-	-
Total	170	144	378	330	31	19	275	195

### LAND HOLDINGS INCLUDING PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table sets out the developed and undeveloped land holdings as at December 31, 2010.

	<u>Developed Acres</u>		<u>Undeveloped Acres</u>		<u>Total Acres</u>	
	Gross	Net	Gross	Net	Gross	Net
Alberta	61,780	41,752	116,205	105,412	177,984	147,164
Saskatchewan	26,657	26,009	68,458	64,666	95,115	90,675
British Columbia	687	172	2,061	258	2,748	428
Total - Canada	89,124	67,933	186,723	170,335	275,847	238,267
Total - USA	600	300	147,355	105,361	147,955	105,661
Total	89,724	68,233	334,079	275,696	423,802	343,928

We currently have no material work commitments on these lands. Over the next 12 months, 28,049 net acres of BlackPearl's undeveloped land will be subject to expiry.

### FORWARD CONTRACTS

As at December 31, 2010, 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 disconnect costs included in the report by Sproule for wells which have reserves assigned. Only well abandonment costs and disconnect costs were deducted by Sproule in estimating future net revenue in the Sproule Report. No allowance for surface lease reclamation or downhole salvage value was included. It does not include costs to abandon pipelines, facilities or wells for which no reserves have been assigned. BlackPearl expects to incur abandonment and reclamation costs on approximately 675 net wells.

Year	Total Proved (M\$)	Total Proved Plus Probable (M\$)
2011	60	0
2012	173	145
2013	370	212
2014	1,103	416
2015	3,452	559
Remaining	4,337	12,500
<b>Total (Undiscounted)</b>	<b>9,495</b>	<b>13,832</b>
<b>Total (Discounted at 10%)</b>	<b>5,732</b>	<b>6,043</b>

BlackPearl has not established a reclamation fund to pay future asset retirement obligation costs. During 2010, the Company incurred \$0.9 million to abandon and reclaim sites.

For purposes of preparation of asset retirement obligations on the Company's December 31, 2010 consolidated financial statements, the Company estimated an undiscounted amount of \$27.5 million (\$18.9 million discounted) to abandon all wells, pipelines and facilities owned by the Company as at December 31, 2010.

#### TAX HORIZON

The Company did not pay any current income taxes in the year ended December 31, 2010. As at December 31, 2010, the Company had approximately \$390 million of tax pools available to be applied against future income for tax purposes (not all tax pools can be fully utilized in any single year).

On a total proved reserves basis, the Sproule Report estimates that the Company will be taxable in 2013. On a proved and probable reserves basis, the Sproule Report indicates the Company will be taxable in 2012. The Sproule Report does not include capital spending on projects that have not been assigned proved and probable reserves. This additional spending could impact the Company's tax horizon.

The Company's tax horizon is dependent on, among other things, anticipated levels of operations, anticipated capital spending, the current tax regime and the current commodity price forecast. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected.

#### COSTS INCURRED

The following table summarizes capital expenditures made by BlackPearl on oil and natural gas properties for the year ended December 31, 2010.

(\$M)	Canada	U.S.	Total
Property acquisition costs - unproved	21,000	-	21,000
Exploration costs <sup>(1)</sup>	8,074	-	2,906
Development costs	66,755	-	66,755
<b>Total</b>	<b>95,829</b>	<b>-</b>	<b>95,829</b>

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, 2010.

	Development wells		Exploratory wells	
	Gross	Net	Gross	Net
Oil wells	36	36	-	-
Gas wells	-	-	-	-
Service Wells	9	9	-	-
Dry	-	-	-	-
<b>Total</b>	<b>45</b>	<b>45</b>	<b>-</b>	<b>-</b>

All of the wells drilled in 2010 were located in Canada, and all of our planned activities for 2011 are located in Canada.

## PRODUCTION ESTIMATES

The following table sets out our working interest production rates for the year ended December 31, 2011 which is reflected in the estimate of gross proven and probable reserves disclosed in the tables contained under "Statement of Reserves and Contingent Resources Data and Other Oil and Gas Information.

	Gross Daily Production Total
<b>Total Proved</b>	
Light & Medium Oil (bbl/d)	1
Heavy Oil (bbl/d)	7,991
Assoc. and Non-Assoc. Gas (Mcf/d)	1,625
Natural Gas Liquids (bbl/d)	5
<b>Total (boe/d)</b>	<b>8,268</b>
<b>Total Probable</b>	
Light & Medium Oil (bbl/d)	0
Heavy Oil (bbl/d)	812
Assoc. and Non-Assoc. Gas (Mcf/d)	170
Natural Gas Liquids (bbl/d)	1
<b>Total (boe/d)</b>	<b>840</b>
<b>Total Proved + Probable</b>	
Light & Medium Oil (bbl/d)	1
Heavy Oil (bbl/d)	8,802
Assoc. and Non-Assoc. Gas (Mcf/d)	1,795
Natural Gas Liquids (bbl/d)	6
<b>Total (boe/d)</b>	<b>9,108</b>

All of BlackPearl's forecasted production for 2011 is expected to come from the Company's Canadian properties. The Onion Lake field in Saskatchewan accounts for 77% (7,052 boe/day) of BlackPearl's total forecasted gross 2011 production.

## PRODUCTION HISTORY

The following table indicates the Company's average gross daily production in 2010 and 2009:

	2010			2009		
	Oil(bbl/d) <sup>(1)</sup>	Gas(mcf/d)	boe/d	Oil(bbl/d) <sup>(1)</sup>	Gas(mcf/d)	boe/d
Onion Lake	5,036	23	5,038	2,276	128	2,297
Mooney	852	933	1,008	1,178	1,469	1,423
Ear Lake	145	62	155	424	145	448
Salt Lake	218	335	274	262	543	353
LongCoulee/Little Bow	9	1,718	295	9	2,407	410
Other	115	384	180	125	890	323
	6,375	3,455	6,951	4,274	5,582	5,254

Note:

(1) Includes natural gas liquids

## NETBACKS

The following table sets forth certain information in respect of production, product prices, royalties, transportation costs, production costs and netbacks received for each quarter of the Company's most recently completed financial year.

	Quarter Ended				Year Ended
	Mar. 31, 2010	30-Jun-10	Sep. 30, 2010	Dec. 31, 2010	2010
<b>Average Daily Production</b> <sup>(1)(2)</sup>					
Oil (bbl/d)	5,941	6,515	6,166	6,871	6,375
Natural Gas (mcf/d)	4,462	3,890	2,881	2,614	3,455
Products Combined (boe/d)	6,685	7,163	6,646	7,307	6,951
<b>Average Net Prices Received</b>					
Oil (\$/bbl)	63.83	55.03	57.17	59.79	58.86
Natural Gas (\$/mcf)	5.01	3.97	3.52	3.59	4.14
Products Combined (boe/d)	60.55	52.58	54.66	57.63	56.31
<b>Transportation Costs</b> <sup>(3)</sup>					
Oil (\$/bbl)	0.91	1.05	1.48	1.06	1.13
Natural Gas (\$/mcf)	0.15	0.13	0.23	0.16	0.16
Products Combined (\$/boe)	0.87	1.00	1.42	1.03	1.08
<b>Royalties</b>					
Oil (\$/bbl)	17.42	14.64	15.04	16.64	15.92
Natural Gas (\$/mcf)	0.09	0.55	1.54	(3.61)	(0.20)
Products Combined (\$/boe)	15.54	13.60	14.61	14.35	14.50
<b>Production Costs</b> <sup>(3)</sup>					
Oil (\$/bbl)	16.39	14.30	13.51	12.95	14.22
Natural Gas (\$/mcf)	7.31	3.52	5.13	4.23	5.19
Products Combined (\$/boe)	17.54	14.31	13.57	12.90	14.51
<b>Netback Received</b> <sup>(5)</sup>					
Oil (\$/bbl)	29.11	25.04	27.14	29.14	27.59
Natural Gas (\$/mcf)	(2.54)	(0.23)	(3.38)	2.81	(1.01)
Netback Received Combined (\$/boe)	26.60	23.67	25.06	29.35	26.22

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, 2011, there were 283,262,387 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.

2010	High (\$/Share)	Low (\$/Share)	Volume
January	2.85	2.42	13,830,158
February	2.65	2.16	14,730,597
March	2.72	2.30	11,281,844
April	3.28	2.66	14,652,806
May	3.20	2.38	16,586,808
June	3.24	2.67	37,891,723
July	3.16	2.70	13,136,509
August	3.30	2.86	10,588,107
September	3.89	3.05	16,206,705
October	4.59	3.65	20,768,250
November	5.48	4.27	21,256,268
December	6.25	5.38	18,357,563

## Prior Sales

The Company has issued the following Common Shares during the 12 month period ended December 31, 2010:

Date	Price per Common Share (\$)	Number of Common Shares <sup>(1)</sup>
December 21, 2009	0.77	250,000
January 5, 2010	0.63	8,334
January 6, 2010	0.77	50,000
January 14, 2010	1.75	5,000
March 8, 2010	0.63	26,667
March 8, 2010	0.77	50,000
March 10, 2010	0.63	36,667
March 10, 2010	1.75	10,000
March 12, 2010	0.77	25,000
March 12, 2010	2.53	9,000
April 1, 2010	0.77	25,000
April 8, 2010	0.77	50,000
April 14, 2010	0.77	25,000
May 11, 2010	2.90	10,350,000 <sup>(2)</sup>
May 12, 2010	0.63	100,000
May 12, 2010	2.53	20,000
May 12, 2010	1.75	13,334
June 11, 2010	0.63	65,000
June 16, 2010	0.63	10,000
June 16, 2010	2.53	4,000
June 16, 2010	1.75	1,667
July 13, 2010	0.63	10,000
August 27, 2010	0.63	3,500
September 17, 2010	0.63	10,000
September 22, 2010	0.77	25,000
September 30, 2010	1.75	6,667
October 4, 2010	0.63	8,333
October 4, 2010	2.53	4,000
October 4, 2010	1.75	5,000
October 7, 2010	0.63	10,000
October 13, 2010	0.91	7,500
November 16, 2010	1.75	3,333
November 19, 2010	2.21	30,000
December 7, 2010	5.00	10,000,000 <sup>(3)</sup>
December 14, 2010	0.63	100,000
December 15, 2010	2.21	8,334
December 17, 2010	0.63	100,000
December 21, 2010	0.63	30,000

### Notes:

(1) Unless otherwise noted, all Common Shares were issued upon exercise of stock options granted under the Company's stock option plan.

(2) On May 11, 2010, the Company issued 10,350,000 Common Shares at a price of \$2.90 per share pursuant to a public offering.

(3) On December 7, 2010, the Company issued 10,000,000 Common Shares at a price of \$5.00 per share pursuant to a public offering.

During the year ended December 31, 2010, the Company granted 2,786,500 options exercisable into 2,786,500 common shares of the Company, the particulars of which are set forth in the following table:

Date of Grant	Number of Securities Issued <sup>(1)</sup>	Exercise Price (\$)
March 15, 2010	100,000 Options	2.60
March 4, 2010	80,000 Options	2.42
June 4, 2010	150,000 Options	2.79
September 1, 2010	75,000 Options	3.06
November 18, 2010	2,306,500 Options	5.08
December 1, 2010	75,000 Options	5.27

Notes:

- (1) Each option entitles the holder to acquire one common share, on the terms and conditions set forth in the Company's stock option plan and expires five years from the date of issuance.

### 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:

<b>Name and Residence</b>	<b>Principal Occupation for Past Five Years</b>	<b>Position</b>	<b>Date Appointed</b>
Keith C. Hill <sup>(4)</sup> West Vancouver, British Columbia, Canada	Mr. Hill is President and Chief Executive Officer of Africa Oil Corp., an oil and gas exploration and production company. 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
John H. Craig <sup>(1)(2)(3)(5)</sup> Toronto, Ontario, Canada	Mr. Craig is a lawyer and partner of Cassels Brock & Blackwell LLP.	Director	May 2009
Brian D. Edgar <sup>(1)(2)(3)(4)</sup> Vancouver, British Columbia, Canada	Mr. Edgar is Executive Chairman of Metalline Mining Company, an exploration stage mining company. From February 2005 to April 2010, Mr. Edgar was President and Chief Executive Officer of Dome Ventures Corporation which was merged with Metalline, April 2010.	Director	Feb. 2006
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
Victor Luhowy <sup>(1)(2)(3)(4)</sup> Priddis, Alberta, Canada	Mr. Luhowy is President, BelAir Petroleum Management Ltd., a private management company. From February 2004 to June 2009, Mr. Luhowy was President and Chief Executive Officer of Mystique Energy Inc.	Director	Jan. 2009
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
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 Exploration Manager of BlackRock Ventures Inc.	Officer	Jan. 2009
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
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

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Corporate Governance and Nominating Committee.
- (3) Member of the Compensation Committee.
- (4) Member of the Reserves Committee.
- (5) Lead Director

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, 2010, our directors and executive officers, as a group, beneficially owned, or controlled or directed, directly or indirectly, 20,389,300 BlackPearl Shares or approximately 7% of the issued and outstanding BlackPearl Shares. In addition, directors and executive officers held 9,645,196 warrants and 8,333,000 options resulting in directors and executive officers holding 12% 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: (a) a cease trade order or similar order; or (b) 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* (Canada).

#### ***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 become 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 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, 2010, the audit committee was comprised of the following individuals:

	<u>Independent <sup>(1)</sup></u>	<u>Financially literate <sup>(1)</sup></u>	<u>Relevant Education and Experience</u>
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:

(1) 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, 2010 and 2009.

Type of Work	2010 Fees	2009 Fees
<b>Audit Fees</b>	158,125	162,884
<b>Audit Related Fees</b> Review of interim financial statements and MD&A, review of changes in accounting policy (IFRS)	66,150	66,150
<b>Other Fees</b> Review of prospectus and IFRS strategy	98,123	55,256
<b>TOTAL</b>	322,398	284,290

#### **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, 2010 that are material to the Company, or knows of any such legal proceedings contemplated.

During the year ended December 31, 2010, 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 – 5<sup>th</sup> 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 auditors' 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](http://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 11, 2011. 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, 2010.

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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010, 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, 2010, prepared October 2010 to January 2011	Canada				
<b>Total</b>			<b>Nil</b>	<b>481,487</b>	<b>Nil</b>	<b>481,487</b>

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 Unconventional Limited  
Calgary, Alberta  
January 18, 2011

Original Signed by Colleen M. Rogers, C.E.T.

\_\_\_\_\_  
Colleen M. Rogers, C.E.T.  
Senior Petroleum Technician and Shareholder

Original Signed by Alec Kovaltchouk, P.Geol.

\_\_\_\_\_  
Alec Kovaltchouk, P.Geol.  
Manager, Geoscience and Associate

Original Signed by Jason Robottom, E.I.T.

\_\_\_\_\_  
Jason Robottom, E.I.T.  
Engineer-in-Training

Original Signed by Victor Verkhogliad, P.Geol.

\_\_\_\_\_  
Victor Verkhogliad, P.Geol.  
Senior Petroleum Geologist

Original Signed by Doug W.C. Ho, P.Eng.

\_\_\_\_\_  
Doug W.C. Ho, P.Eng.  
Vice-President, Engineering and Director

## **Form 51-101F2 (Contingent Resources)**

### **Report on Contingent Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor**

### **Report on Contingent Bitumen Resource Data**

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

1. We have evaluated the Company's Contingent Bitumen Resources Data in the Blackrod Area of Alberta as at December 31, 2010. The resources data are low, best, and high estimates of contingent bitumen resources and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The Resource Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Resource 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).

Sproule Associates Limited

3. Those standards require that we plan and perform an evaluation of contingent bitumen resources to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource 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 low, best and high contingent bitumen resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resources data of the Company evaluated by us as of December 31, 2010, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Resources (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)		
			Low Estimate (MM\$)	Best Estimate (MM\$)	High Estimate (MM\$)
Sproule	Evaluation of the Contingent Bitumen Resources in the Blackrod Area of Alberta of BlackPearl Resources Inc., as of December 31, 2010, prepared October 2010 to January 2011	Canada			
<b>Total</b>			<b>1,776</b>	<b>2,011</b>	<b>2,250</b>

5. In our opinion, the resource 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 resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Sproule Associates Limited

Executed as to our report referred to above:

Sproule Unconventional Limited  
Calgary, Alberta  
February 23, 2011

Original Signed by Kevin Major-Hansford, E.I.T.

\_\_\_\_\_  
Kevin Major-Hansford, E.I.T.  
Engineer-in-Training

Original Signed by Wesley J. Waddell, P.Geol.

\_\_\_\_\_  
Wesley J. Waddell, P.Geol.  
Senior Petroleum Geologist and Associate

Original Signed by John L. Chipperfield, P.Geol.  
on behalf of ~~Doug W.C. Ho, P.Eng.~~\_\_\_\_\_

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

## **Form 51-101F2 (Contingent Resources)**

### **Report on Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor**

### **Report on Contingent Heavy Oil Resource Data**

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

1. We have evaluated the Company's Contingent Heavy Oil Resources Data in the Mooney Area of Alberta as at December 31, 2010. The resources data are low, best, and high estimates of contingent resources and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The Resource Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Resource 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).

Sproule Unconventional Limited

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource 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 low, best and high contingent heavy oil resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resources data of the Company evaluated by us as of December 31, 2010, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Resources (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)		
			Low Estimate (MM\$)	Best Estimate (MM\$)	High Estimate (MM\$)
Sproule	Evaluation of the Contingent Heavy Oil Resources in the Mooney Area of Alberta of BlackPearl Resources Inc., as of December 31, 2010, prepared November 2010 to January 2011	Canada			
<b>Total</b>			<b>290</b>	<b>257</b>	<b>341</b>

5. In our opinion, the resource 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 resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Sproule Unconventional Limited

Executed as to our report referred to above:

Sproule Unconventional Limited  
Calgary, Alberta  
February 23, 2011

Original Signed by Jason Robottom, E.I.T.

\_\_\_\_\_  
Jason Robottom, E.I.T.  
Engineer-in-Training

Original Signed by Alec Kovaltchouk, P.Geol.

\_\_\_\_\_  
Alec Kovaltchouk, P.Geol.  
Manager, Geoscience and Associate

Original Signed by Chris Galas, Ph.D., P.Eng.

\_\_\_\_\_  
Chris Galas, Ph.D., P.Eng.  
Manager, Reservoir Studies and Associate

Original Signed by Alexey Romanov, Ph.D., M.Sc.

\_\_\_\_\_  
Alexey Romanov, Ph.D., M.Sc.  
Geological Reservoir Simulation Specialist

Original Signed by John L. Chipperfield, P.Geol.  
on behalf of Doug W.C. Ho, P.Eng.

\_\_\_\_\_  
Doug W.C. Ho, P.Eng.  
Vice-President, Engineering and Director

## **Form 51-101F2 (Contingent Resources)**

### **Report on Contingent Resource Data by Independent Qualified Reserves and Resources Evaluator or Auditor**

### **Report on Contingent Heavy Oil Resource Data**

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

1. We have evaluated the Company's Contingent Heavy Oil Resources Data in the Onion Lake Area of Alberta and Saskatchewan as at December 31, 2010. The resources data are low, best, and high estimates of contingent heavy oil resources and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The Resource Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Resource 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).

Sproule Unconventional Limited

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the resource data are free of material misstatement. An evaluation also includes assessing whether the resource 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 low, best and high contingent heavy oil resources, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the resources data of the Company evaluated by us as of December 31, 2010, and reported on to the Company's management and Board of Directors:

Independent Qualified Resources Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Resources (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)		
			Low Estimate (MM\$)	Best Estimate (MM\$)	High Estimate (MM\$)
Sproule	Evaluation of the Contingent Heavy Oil Resources in the Onion Lake Area of Alberta and Saskatchewan of BlackPearl Resources Inc., as of December 31, 2010, prepared November 2010 to January 2011	Canada			
<b>Total</b>			<b>675</b>	<b>817</b>	<b>999</b>

5. In our opinion, the resource 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 resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Sproule Unconventional Limited

Executed as to our report referred to above:

Sproule Unconventional Limited  
Calgary, Alberta  
February 23, 2011

Original Signed by Colleen Rogers, C.E.T.

\_\_\_\_\_  
Colleen Rogers, C.E.T.  
Senior Petroleum Technician and Shareholder

Original Signed by Kevin Major-Hansford, E.I.T.

\_\_\_\_\_  
Kevin Major-Hansford, E.I.T.  
Engineer-in-Training

Original Signed by Alec Kovaltchouk, P.Geol.

\_\_\_\_\_  
Alec Kovaltchouk, P.Geol.  
Manager, Geoscience and Associate

Original Signed by Victor Verkhogliad, P.Geol.

\_\_\_\_\_  
Victor Verkhogliad, P.Geol.  
Senior Petroleum Geologist

Original Signed by John L. Chipperfield, P.Geol.  
on behalf of Doug W.C. Ho, P.Eng.

\_\_\_\_\_  
Doug W.C. Ho, P.Eng.  
Vice-President, Engineering and Director

## FORM 51-101F3

## BLACKPEARL RESOURCES INC.

## REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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 and resource data, which are estimates of proved reserves and probable reserves and contingent resources and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

Sproule Unconventional Limited, independent qualified reserves evaluators, has evaluated the Company's reserves and resource data. The reports of Sproule Unconventional Limited will be filed with securities regulatory authorities concurrently with this report.

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

- (a) reviewed the Company's procedures for providing information to Sproule Unconventional Limited;
- (b) met with Sproule Unconventional Limited to determine whether any restrictions affected the ability of Sproule Unconventional Limited to report without reservation; and
- (c) reviewed the reserves and resources data with management and Sproule Unconventional 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. The board of directors has approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves and resources data and other oil and gas information;
- (b) the filing of Forms 51-101F2 which are the reports of Sproule Unconventional Limited on the reserves and resources data; and
- (c) the content and filing of this report.

Because the reserves and resources 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 "John Festival"*

\_\_\_\_\_  
John Festival  
President and Chief Executive Officer

*Signed "Don Cook"*

\_\_\_\_\_  
Don Cook  
Chief Financial Officer

*Signed "Keith Hill"*

\_\_\_\_\_  
Keith Hill  
Director

*Signed "Brian Edgar"*

\_\_\_\_\_  
Brian Edgar  
Director

February 25, 2011

**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 member's 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. Authority**

- (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. Relationship with External Auditors**

- (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. Accounting Systems, Internal Controls and Procedures**

- (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.