PAREX RESOURCES INC

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2013

MARCH 19, 2014

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ABBREVIATIONS AND CONVENTIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

bbls	barrels
mbbls	one thousand barrels
mmbbls	one million barrels
NGLs	natural gas liquids
bbls/d	barrels of oil or natural gas liquids per day
mbbls/d	one thousand barrels per day

Natural Gas

mcf	one thousand cubic feet
mmcf	one million cubic feet
bcf	one billion cubic feet
Mcf/d	one thousand cubic feet per day
MMcf/d	one million cubic feet per day

Other

BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
mboe	one thousand barrels of oil equivalent
mmboe	one million barrels of oil equivalent
bfpd	barrels of fluid per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
WTI	West Texas Intermediate

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Certain other terms used herein but not defined herein are defined in NI 51-101 (as defined herein) and/or CSA 51-324 (as defined herein) and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and/or CSA 51-324.

Any references in this Annual Information Form to initial and/or final test rates or production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter. These test results are not necessarily indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company.

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
cubic feet	cubic metres ("m3")	0.028
cubic metres	cubic feet	35.301
bbls	m3	0.159
m3	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.4710

Unless otherwise indicated, references in this Annual Information Form to "dollars" and "$" are to United States dollars ("**U.S. dollars**").

In all cases where percentage figures are provided, such percentages have generally been rounded to the nearest whole number.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2013.

CURRENCY AND EXCHANGE RATES

The following table sets forth, for each of the periods indicated, the high and low rates of exchange of Canadian dollars into U.S. dollars, the average of the exchange rates during each such period and the end-of-period rate. Such rates are shown as, or are derived from, the reciprocals of the noon buying rates in New York City for cable transfers payable in Canadian dollars, as available on the Bank of Canada website. On March 18, 2014, the noon buying rate for one U.S. dollar in Canadian dollars as certified by the Bank of Canada was $1.1086.

	Year Ended December 31		
	2013	**2012**	**2011**
Highest rate during the period	1.0697	1.0418	1.0604
Lowest rate during the period	0.9839	0.9710	0.9449
Average noon spot rate for the period	1.0299	0.9996	0.9891
Rate at the end of the period	1.0636	0.9949	1.0162

Note:

(1) The average of the daily noon buying rates during the period.

NON-GAAP TERMS

Funds flow used in, or from operations, operating netback per barrel and adjusted net income may from time to time be used by the Company, but do not have any standardized meaning under IFRS and may not be comparable to similar measures presented by other companies. Funds flow used in, or from operations includes all cash generated from operating activities and is calculated before changes in non-cash working capital. Adjusted net income is determined by adding back any losses or deducting any gains associated with the Company’s derivative financial liability. Operating netback per barrel equals sales revenue, less royalties, production expense and transportation expense, divided by total equivalent sales volume excluding purchased oil volumes. Management uses these non-GAAP measures for its own performance measurement and to provide shareholders and investors with additional measurements of the Company’s efficiency and its ability to fund a portion of its future capital expenditures.

CERTAIN DEFINITIONS

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

Selected Defined Terms

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

"**Acquired Assets**" means a 50 percent working interest in all of the petroleum rights, facilities and other tangibles and miscellaneous interests of the Vendor and its Subsidiaries relating to certain crude oil properties and related assets located on Block LLA-16, Block LLA-20, Block LLA-29 and Block LLA-30 in the Llanos Basin in Colombia;

"**Acquisition Agreement**" means the purchase agreement among Parex Colombia, the Vendor and Subco dated April 20, 2011, pursuant to which the Company, through Parex Colombia, agreed to purchase the Acquired Assets, through the acquisition of all of the shares of Subco, as described in more detail under *General Development of the Business – History of the Company*;

"**C&T Cos**" means Parex Barbados and Parex Colombia and, thereby, indirectly Parex Trinidad;

"**C&T Cos Shares**" means the common shares in each of the C&T Cos;

"**Change of Control**" has the meaning attributed thereto under *Description of Debentures – Purchase Upon a Change of Control*;

"**Change of Control Purchase Date**" means the date specified for purchase in a Debenture Offer;

"**Common Share Interest Payment Election**" means the delivery by the Company to the Debenture Trustee for sale, a sufficient number of Common Shares to satisfy the Interest Obligation on the Interest Payment Date, in which event holders of the Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares;

"**Common Shares**" means the common shares in the capital of the Company;

"**Company**" or "**Parex**" means Parex Resources Inc., a corporation incorporated under the ABCA, or Parex Resources Inc. and its direct and indirect Subsidiaries on a consolidated basis, where the context requires;

"**Conversion Price**" means Cdn$10.15 per Common Share, subject to adjustment in accordance with the Indenture;

"**Current Market Price**" has the meaning attributed thereto under *Description of Debentures –Conversion Privilege*;

"**Debenture Offer**" has the meaning attributed thereto under *Description of Debentures – Repurchase upon a Change of Control*;

"**Debenture Trustee**" means Valiant Trust Company;

"**Debentures**" means the Cdn$85,000,000 aggregate principal amount of 5.25 percent convertible unsecured subordinated debentures of the Company;

"**EDC**" means Export Development Canada;

"**Event of Default**" has the meaning attributed thereto under *Description of Debentures – Events of Default*;

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada which is currently in accordance with IFRS;

"**IFRS**" means International Financial Report Standards as issued by the International Accounting Standards Board;

"**Indenture**" means the indenture dated May 17, 2011 between the Company and the Debenture Trustee under which the Debentures were issued;

"**Interest Obligation**" means the Company's obligation to pay interest on the Debentures in accordance with the Indenture;

"**Interest Payment Date**" means June 30 and December 31 in each year;

"**Maturity Date**" means June 30, 2016;

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*;

"**Parex Barbados**" means Parex Resources (Barbados) Ltd., a corporation organized under the laws of Barbados;

"**Parex Barbados Shares**" means the common shares in the capital of Parex Barbados;

"**Parex Bermuda**" means Parex Resources (Bermuda) Ltd., a corporation organized under the laws of Bermuda;

"**Parex Colombia**" means Parex Resources (Colombia) Ltd., a corporation organized under the laws of Barbados;

"**Parex Colombia Shares**" means the common shares in the capital of Parex Colombia;

"**Parex Trinidad**" means Parex Resources (Trinidad) Ltd., a corporation organized under the laws of Trinidad & Tobago;

"**Parex Warrants**" means Common Share purchase warrants of Parex, each whole warrant entitling the holder thereof to purchase one Common Share at a price of Cdn$3.00 from November 6, 2009 to December 6, 2009;

"**PARI Common Shares**" means the Class A shares in the capital of PARI;

"**Petro Andina**" or "**PARI**" means Petro Andina Resources Inc.;

"**Pluspetrol**" means Pluspetrol Resources Corporation N.V., a corporation existing under the laws of The Netherlands and any successor corporation;

"**Ramshorn**" means Ramshorn International Limited, a corporation organized under the laws of Bermuda;

"**Ramshorn Acquisition**" means the acquisition by Parex Bermuda of all of the class A shares of Ramshorn, as described in more detail under *General Development of the Business – History of the Company*;

"**Redemption Date**" means the date set for the redemption of the Debentures;

"**Remora Acquisition**" means the indirect acquisition by the Company of the Acquired Assets pursuant to the Acquisition Agreement through the acquisition of all of the shares of Subco, which owns all of the Acquired Assets, as described in more detail under *General Development of the Business – History of the Company*;

"**Remora Purchase Price**" means the purchase price for the Acquired Assets of $255,000,000, subject to closing adjustments;

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

"**Senior Indebtedness**" has the meaning attributed thereto under *Description of Debentures – Subordination*;

"**Subco**" means Parex Energy Colombia Ltd. (formerly Remora Energy Colombia Ltd.);

"**Subsidiaries**" has the meaning attributed thereto under the ABCA;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, each as amended from time to time;

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

"**TSXV**" means the TSX Venture Exchange, Inc.; and

"**Vendor**" means, collectively, Remora Energy International L.P. and its Subsidiaries.

Selected Oil and Gas Terms

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**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 (Petroleum Society), as amended from time to time;

"**CSA 51-324**" means Staff Notice 51-324 - *Glossary To NI 51-101 Standards of Disclosure For Oil And Gas Activities* of the Canadian Securities Administrators;

"**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown;

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

"**developed 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;

"**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 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;

"**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 (sometimes referred to as "prospecting costs") 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 (collectively sometimes referred to as "geological and geophysical costs");

(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 wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum engineers of Calgary, Alberta;

"**GLJ Report**" means the report of GLJ dated February 20, 2014 evaluating the oil and natural gas reserves of the Company as at December 31, 2013;

"**gross**" means:

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

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

(c) in relation to properties, the total area of properties in which a reporting issuer has an interest;

"**ICE Brent**" means Intercontinental Exchange Brent;

"**net**" means:

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

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

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

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

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

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

"**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;

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates; and

"**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.

FORWARD LOOKING STATEMENTS

Certain information regarding Parex set forth in this document, including management of the Company's ("**Management**") assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. The use of any of the words "plan", "expect", "forecast", "project", "intend", "believe", "anticipate", "estimate" or other similar words, or statements that certain events or conditions "may" or "will" occur are intended to identify forward-looking statements. Such statements represent Parex' internal projections, estimates or beliefs concerning, among other things, future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. These statements are only predictions and actual events or results may differ materially. Although Management believes that the expectations reflected in the forward-looking statements are reasonable, it cannot guarantee future results, levels of activity, performance or achievement since such expectations are inherently subject to significant business, economic, operational, competitive, political and social uncertainties and contingencies. Many factors could cause Parex' actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, Parex.

In particular, forward-looking statements included in this Annual Information Form include, but are not limited to, statements with respect to:

- the size of, and future net revenues from, oil reserves;
- the performance characteristics of the Company's oil properties;
- supply and demand for oil and natural gas;
- drilling plans, including completion and testing, and the anticipated timing thereof;
- anticipated timing of commissioning OTP (as defined herein) expansion;
- treatment under governmental regulatory regimes and tax laws;
- receipt of regulatory approvals;
- financial and business prospects and financial outlook;
- results of operations;
- production, future costs, reserves and production estimates;
- activities to be undertaken in various areas including the fulfillment of exploration commitments;
- timing of drilling, completion and tie in of wells;
- tax horizon;
- access to facilities and infrastructure;
- timing of development of undeveloped reserves;
- planned capital expenditures, the timing thereof and the method of funding;
- financial condition, access to capital and overall strategy;
- development and drilling plans for the Company's assets;
- the quantity of the Company's reserves;
- the Company's oil production levels;
- the Company's expectations regarding its ability to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; and
- the Company's expectations and plans with respect to the Lawsuit (as defined herein).

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. The recovery and reserve estimates of Parex' reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements.

These forward-looking statements are subject to numerous risks and uncertainties, including but not limited to, the impact of general economic conditions in Canada, Colombia, Bermuda, Barbados and Trinidad & Tobago; industry conditions including changes in laws and regulations including adoption of new environmental laws and regulations, and changes in how they are interpreted and enforced, in Canada, Colombia, Bermuda, Barbados and Trinidad & Tobago; competition; lack of availability of qualified personnel; the results of exploration and development drilling and related activities; risks related to the ability of partners to fund capital work programs and other matters requiring partner approval; imprecision in reserve and resource estimates; the production and growth potential of Parex' assets; obtaining required approvals of regulatory authorities, in Canada, Colombia and Trinidad & Tobago; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; volatility in market prices for oil, NGL's and natural gas; fluctuations in foreign exchange or interest rates; environmental risks; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry; ability to access sufficient capital from internal and external sources; risk that the Company will not be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; risks related to the Lawsuit; the risks discussed herein under *Risk Factors*; and other factors, many of which are beyond the control of the Company.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Parex' operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

Although the forward-looking statements contained in this Annual Information Form are based upon assumptions which Management believes to be reasonable, the Company cannot assure investors that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this Annual Information Form, Parex has made assumptions regarding, but not limited to: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; uninterrupted access to infrastructure; future exchange rates; the price of oil, NGLs and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; recoverability of reserves; royalty rates; future operating costs; receipt of regulatory approvals; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop the Company's oil and gas properties in the manner currently contemplated; that current or, where applicable, proposed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; that the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; that the Company will be able to obtain contract extensions or fulfill the contractual obligations required to retain its rights to explore, develop and exploit any of its undeveloped properties; and other matters.

Forward-looking statements and other information contained herein concerning the oil and natural gas industry in the countries in which the Company operates and the Company's general expectations concerning this industry are based on estimates prepared by Management using data from publicly available industry sources as well as from resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry involves numerous risks and uncertainties and is subject to change based on various factors.

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

CORPORATE STRUCTURE

General

Parex was incorporated under the ABCA on August 17, 2009 as "1485196 Alberta Ltd." On September 29, 2009, Parex filed articles of amendment to remove its private company restrictions and change its name to "Parex Resources Inc.".

The Company's registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta T2P 1G1 and its head office is located at 1900, 250 - 2nd Street S.W., Calgary, Alberta, T2P 0C1.

The Company is a reporting issuer in each of the Provinces of Canada and the Common Shares and Debentures of Parex trade on the TSX under the symbols "PXT" and "PXT.DB", respectively.

Intercorporate Relationships

As at the date hereof, the Company has six direct or indirect wholly-owned subsidiaries (each a "**Subsidiary**" and collectively, the "**Subsidiaries**"). Unless the context otherwise requires, references herein to "Parex" or the "Company" mean Parex Resources Inc. or Parex Resources Inc. and its direct and indirect Subsidiaries on a consolidated basis, where the context requires.

The following chart sets forth the name of each Subsidiary, the jurisdiction of incorporation and laws of incorporation, the registered holder of voting shares of each Subsidiary, the percentage of voting shares held and the business conducted by each Subsidiary:

Name of Subsidiary	Jurisdiction of Incorporation and Laws of Incorporation	Registered Holder of Voting Securities and Percentage Held	Business Conducted
Parex Resources Holdings Ltd.	Alberta (ABCA)	Parex (100%)	Holding company.
Parex Resources (Barbados) Ltd.	Barbados (*Companies Act of Barbados* and licensed under the *International Business Companies Act*)	Parex (100%)	Holding company.
Parex Resources (Colombia) Ltd.	Barbados (*Companies Act of Barbados*)	Parex Barbados (100%)	A portion of the Company's activities in Colombia are conducted through a Colombian branch of this entity.
Parex Resources (Trinidad) Ltd.	Trinidad & Tobago (*Companies Act*, 1995)	Parex Barbados (100%)	All of the Company's activities in Trinidad & Tobago are conducted through this entity.
Parex Resources (Bermuda) Ltd.	Bermuda (*Companies Act 1981*)	Parex Barbados (100%)	Holding company.
Ramshorn International Limited	Bermuda (*Companies Act 1981*)	Parex Bermuda (100%)	A portion of the Company's activities in Colombia are conducted through a Colombian branch of this entity.

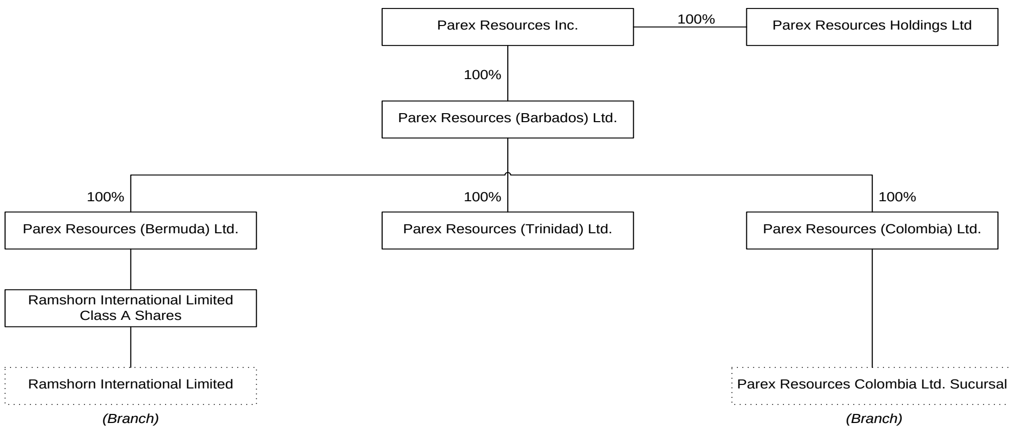
Effective May 31, 2010, Parex reorganized its holdings in Parex Colombia, such that Parex Barbados became the sole holder of all of the issued and outstanding Parex Colombia Shares and Parex holds all of the non-voting preferred shares of Parex Colombia. See *Corporate Structure* for further information.

Effective June 28, 2013, Parex Energy Colombia Ltd. was amalgamated with Parex Colombia. Their respective Colombian branches were also amalgamated.

Parex provides certain administrative, management and technical support services to certain of its Subsidiaries pursuant to administrative, management and technical support service agreements. The Company has entered into administrative, management and technical support service agreements with Parex Trinidad, Parex Colombia, and Ramshorn in order to provide these Subsidiaries with support services from Canada.

Corporate Structure

The following chart illustrates the Company's current organizational structure:



Note:

(1) Parex Barbados is the sole holder of all of the issued and outstanding Parex Colombia Shares and Parex holds all of the non-voting preferred shares of Parex Colombia.

The Company's organizational structure facilitates its business as a multijurisdictional company whose operations are located outside of Canada. Parex has two subsidiaries whose activities in Colombia are each conducted through a Colombian branch. Conducting business by way of a Colombian branch is desirable as it minimizes the corporate organizational burden in Colombia. The Company currently has two Colombian branches as it has completed two corporate acquisitions since inception. In time the Company expects to amalgamate or merge these subsidiaries doing business in Colombia into one entity.

All of the Company’s subsidiaries (which by definition excludes the Company’s Colombian branches) are domiciled in countries where the legal system is based on the British common law system. Colombia’s legal system is based upon civil code. Barbados, Bermuda and Trinidad & Tobago also have a banking system and advisory services (legal and accounting) that are comparable to North America. Trinidad & Tobago and Barbados have a tax treaty with Canada. Bermuda has a disclosure agreement with Canada.

To help manage the risks of a multi-jurisdictional organizational structure, the Company employs knowledgeable people and engages advisors in each country the Company operates to review and comment on the organizational structure as appropriate.

GENERAL DEVELOPMENT OF THE BUSINESS

History of the Company

General

Parex was originally incorporated on August 17, 2009 for the purpose of completing the Arrangement (as defined below) and prior to completion of the Arrangement did not carry on any active business other than in connection with the Arrangement and related matters.

In connection with a statutory arrangement (the "**Arrangement**") carried out pursuant to Section 193 of the ABCA involving PARI, Pluspetrol and certain other parties, Pluspetrol, through a series of transactions, acquired all of the outstanding PARI Common Shares. Under the Arrangement, a holder of PARI Common Shares received, for each PARI Common Share, Cdn$7.65 in cash, one Common Share of Parex and one-tenth of a Parex Warrant. Each whole Parex Warrant entitled the holder thereof to purchase one Common Share at a price of Cdn$3.00 for a period of 30 days from the effective date of the Arrangement, which occurred on November 6, 2009.

Pursuant to the Arrangement, Parex acquired PARI's assets located in Colombia and Trinidad & Tobago and related obligations through the acquisition of all of the issued and outstanding C&T Cos Shares. The C&T Cos were indirect wholly owned subsidiaries of PARI formed for the purpose of engaging in the business of acquiring properties and exploring for, developing and producing crude oil and natural gas in Trinidad & Tobago and Colombia. Parex Barbados holds all of the issued and outstanding common shares of Parex Trinidad and Parex Colombia.

On September 29, 2009, Parex closed a bought deal private placement (the "**Parex Private Placement**") whereby Parex issued 6,670,000 subscription receipts (the "**Arrangement Subscription Receipts**") at a price of Cdn$3.00 per Arrangement Subscription Receipt for gross aggregate proceeds of approximately Cdn$20 million. The proceeds of the Parex Private Placement were held in escrow pending the satisfaction of certain conditions, including receipt of all necessary court, regulatory, securityholder and stock exchange approvals for the Arrangement, the completion of the Parex Management Private Placement (as defined below) and the completion of certain steps of the Arrangement. Upon these conditions being met and as part of the Arrangement, the net proceeds of the Parex Private Placement were released to Parex and each Arrangement Subscription Receipt was converted into one Common Share without additional payment.

As part of the Arrangement, Parex completed a private placement of 3,333,333 Common Shares at a subscription price of Cdn$3.00 per share for gross proceeds of up to Cdn$10 million to directors, officers and employees of the Company (the "**Parex Management Private Placement**").

Upon completion of the Arrangement, Parex became a reporting issuer in each of the Provinces of Canada and the Common Shares and the Parex Warrants commenced trading on the TSXV on November 12, 2009, under the symbols "PXT" and "PXT.WT", respectively. The Parex Warrants were subsequently delisted upon their expiry on December 6, 2009.

On June 29, 2011, Parex Colombia, completed the acquisition of the Acquired Assets through the purchase of all of the shares of an indirect wholly-owned subsidiary of the Vendor, Parex Energy Colombia Ltd. (formerly, Remora Energy Colombia Ltd.) ("**Subco**"), for consideration of $255 million, subject to closing adjustments. Prior to the Remora Acquisition, Parex Colombia held the remaining 50 percent working interest in the Acquired Assets. The Remora Purchase Price was funded with a portion of the net proceeds of a bought deal financing completed by the Company, pursuant to which the Company issued: (i) 31.05 million subscription receipts of Parex (the "**Remora Subscription Receipts**") at a price of Cdn$7.00 per Remora Subscription Receipt for gross proceeds of Cdn$217.35 million; and (ii) Cdn$85.0 million aggregate principal amount of 5.25 percent extendible convertible unsecured subordinated debentures of Parex, for total combined gross proceeds of Cdn$302.35 million. In conjunction with the closing of the Remora Acquisition, each Remora Subscription Receipt was automatically converted into one

Common Share without any further action on the part of the holder and without payment of additional consideration. Also in conjunction with closing of the Remora Acquisition, the maturity date of the Debentures was automatically extended from the initial maturity date of July 15, 2011 (the "**Initial Maturity Date**") to June 30, 2016.

On October 3, 2011, the Common Shares and Debentures began trading on the TSX.

On April 12, 2012, Parex Bermuda entered into a purchase and sale agreement with a Bermuda based company, Nabors Global Holdings II (the "**Seller**") to acquire the class A shares of its wholly owned subsidiary, Ramshorn (the "**Ramshorn Acquisition**"), the operations of which included interests in five exploration blocks located in Llanos Basin and two blocks located in Middle Magdalena Basin in Colombia for a total of approximately 567,000 gross acres (276,000 net acres). The Ramshorn Acquisition closed on April 12, 2012. The consideration paid for the shares of Ramshorn was approximately US$71.8 million in cash, including customary closing adjustments, which was funded from cash on hand. Parex also assumed $17.7 million of letters of credit related to Ramshorn's interests post closing. See *Legal Proceedings and Regulatory Actions* in this Annual Information Form.

On May 23, 2012, Parex entered into a $200 million senior secured credit facility with a syndicate of banks led by a major Canadian bank. The initial borrowing base was $50 million but has since been increased to $100 million. See *Bank Debt* in this Annual Information Form.

On May 31, 2013, Parex completed the purchase of its partner’s 50 percent working interest in the Cabrestero block of Colombia (the "**Cabrestero Block**") for $12.5 million before adjustments.

On July 9, 2013, Parex signed a farm-in agreement for the VMM-11 block (the "**VMM-11 Block**") in the Middle Magdalena Basin of Colombia.

On July 26, 2013, Parex completed the purchase of its partner’s 50 percent working interest in the Morpho block of Colombia (the "**Morpho Block**") in return for a 4% net profit interest royalty, subject to regulatory approval.

On August 1, 2013, Parex signed an assignment agreement for a 100 percent working interest and operatorship of the Cebucan block in the Llanos Basin of Colombia (the "**Cebucan Block**"). Pursuant to the terms of the agreement, at the assignment of such working interest by the regulator, Parex will pay $4.5 million.

On August 19, 2013, Parex Trinidad entered into a farm-out agreement for the Moruga Block (as defined herein) in Trinidad. Under the terms of the farm-out agreement, the farmee earned a 20 percent participating interest in the Moruga Block after providing Parex Trinidad with a $2 million payment. The farmee, as contract operator will also earn an additional 31 percent participating interest in the block upon completion of: (i) paying 100 percent of Parex Trinidad’s costs to work-over Snowcap-1 well and place it on production; (ii) paying 100 percent of Parex Trinidad’s costs to drill, complete and test an exploration well within 9 months of the farm-out agreement effective date; and (iii) paying 100 percent of Parex Trinidad’s costs to drill, complete and test a second exploration well within 6 months of the rig release of the first exploration well. If all the Moruga Block farm-out agreement terms are fulfilled by the farmee, Parex Trinidad will transfer operatorship to the farmee and reduce its participating interest from 83.8 percent to 32.8 percent.

On September 18, 2013, Parex Trinidad, as operator of the onshore Central Range Shallow Block and Central Range Deep Block notified the Trinidad & Tobago Ministry of Energy and Energy Affairs that it will relinquish both Central Range Blocks, effective immediately. Parex Trinidad has satisfied the contractual relinquishment obligations as per the requirements of the Central Range Block production sharing contracts.

On October 24, 2013, Parex signed a farm-in agreement for the LLA-24 block in the Llanos Basin of Colombia (the "**LLA-24 Block**"). Pursuant to the terms of the farm-in agreement, Parex receives a 70 percent working interest, operatorship and has a commitment to pay 100 percent of the drilling of one exploration well to a depth of approximately 8,000 feet, subject to regulatory approval.

Operational Activities

For a description of the Company's exploration, development and production activities in 2011, 2012 and 2013, see *Description of the Business and Operations* and *Principal Properties* in this Annual Information Form. Further, a brief summary for each of the three years is provided below:

Year ended December 31, 2011

- production averaged 5,345 bbls/d in 2011 as compared to 306 bbls/d in the fourth quarter of 2010;
- funds flow from operations for the year ended December 31, 2011 was $97.9 million, as compared to $7.7 million of funds used in operations for the year ended December 31, 2010;
- the average realized sales price in Colombia for 2011 was $100.43/bbl generating an operating netback of $69.48/bbl; and
- the Company drilled and tested 18 gross wells in Colombia during 2011, of which 11 were development or service wells.

Year ended December 31, 2012

- achieved annual average oil production in 2012 of 11,407 bbls/d, an increase of 113% over average 2011 production volumes of 5,345 bbls/d;
- realized Brent referenced sales price of $109.18/bbl and an operating netback of $73.41/bbl;
- generated year end funds flow from operations of $241.6 million ($2.23 per share basic) and adjusted net income of $32.6 million ($0.30 per share basic). Funds flow increased due to continued strong operating netbacks, production growth and exploration success;
- the Company participated in drilling 33 gross wells in Colombia and 2 in Trinidad, resulting in 25 oil wells, 6 disposal wells and 4 dry and abandoned, for a success rate of 87 percent; and
- the Company began 2012 with interests in 6 blocks in Colombia and production primarily from the Kona field and exited 2012 with interests in 14 blocks in Colombia and a diversified production base of ten fields.

Year ended December 31, 2013

- achieved annual average oil production in 2013 of 15,854 bbls/d, an increase of 40 percent over average 2012 production volumes of 11,407 bbls/d;
- realized Brent referenced sales price of $104.20/bbl and an operating netback of $62.70/bbl;
- generated funds flow from operations in 2013 of $269.9 million ($2.49 per share basic). Funds flow has increased from the prior year due to production growth from exploration and appraisal success;
- the Company participated in drilling 37 gross wells in Colombia resulting in 25 oil wells, 4 disposal wells, 3 untested and 5 dry and abandoned, for a success rate of 83 percent; and
- increased land holdings in Colombia by 469,944 net acres to 1,417,023 net acres.

See *Principal Properties* in this Annual Information Form.

Recent Developments

In connection with a lawsuit (the "**Lawsuit**") relating to Ramshorn filed in 2012 in the 61st Judicial District Court of Harris Country Texas (the "**Texas Court**") (see *Legal Proceedings and Regulatory Actions* in this Annual Information Form), on January 28, 2014, the Texas Court of Appeals (the "**Texas Appeal Court**") reversed the decision of the Texas Court respecting Parex and dismissed all of the Texas based private company's (the "**Plaintiff**") claims against Parex for lack of jurisdiction. The Texas Appeal Court also affirmed the decision of the Texas Court dismissing all of the Plaintiff's claims against Parex Bermuda for lack of jurisdiction. Lastly, the Texas Appeal Court affirmed the decision of the Texas Court respecting Ramshorn such that Ramshorn remains subject to the Lawsuit. The causes of action alleged against Ramshorn in the Lawsuit all relate to acts and conduct by Ramshorn that the Plaintiff alleges took place prior to Parex Bermuda's acquisition of Ramshorn. On February 12, 2014, the Plaintiff filed a combined motion requesting an initial reconsideration by the Texas Appeal Court of its decision regarding the Texas Courts dismissal of Parex and Parex Bermuda as ruled on January 28, 2014. The Plaintiff's motion was entirely rejected by the Texas Appeal Court on March 6, 2014. On March 7, 2014 the Plaintiff filed a Statement of Claim at the Court of Queen's Bench of Alberta naming Parex, Parex Bermuda and RBC Dominion Securities, Inc. as defendants and setting forth causes of action and remedies substantially the same as have been alleged in the Lawsuit. This Statement of Claim has not been served on Parex or Parex Bermuda and unless and until such service occurs the Plaintiff may not pursue the action against either Parex or Parex Bermuda nor are Parex or Parex Bermuda obligated to take any steps in connection therewith.

Significant Acquisitions

Parex did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

The Company, through its Subsidiaries, is engaged in oil and natural gas exploration, development and production in South America.

Parex Resources (Barbados) Ltd.

Parex Barbados was incorporated on January 24, 2008 under the *Companies Act* of Barbados. Parex Barbados does not own any operating oil and gas assets but was incorporated for the purpose of incorporating a subsidiary under the laws of Trinidad & Tobago, being Parex Trinidad, and subsequently, to hold 100 percent of the voting shares of Parex Trinidad. Parex Barbados also holds 100 percent of the voting shares of Parex Colombia and Parex Bermuda. Parex Barbados also facilitates future capitalization of its subsidiaries.

Parex Resources (Trinidad) Ltd.

Parex Trinidad was incorporated on February 6, 2008 under the *Companies Act*, 1995 of Trinidad & Tobago for the purposes of carrying on oil exploration and development activities in Trinidad & Tobago.

Central Range Blocks

On December 12, 2007, PARI entered into a joint venture agreement (the "**JVA**") with Voyager Energy Ltd. ("**VEL**" or "**Voyager**"), now a wholly owned subsidiary of Niko Resources Ltd. (**"Niko"**) relating to participation in the production sharing contracts ("**PSCs**") with the Republic of Trinidad & Tobago for the central range deep blocks (the "**Central Range Deep Blocks**") and central range shallow horizon blocks (the "**Central Range Shallow Blocks**" and collectively with the Central Range Deep Blocks, the "**Central Range Blocks**").

Parex Trinidad has entered into joint operating agreements with Niko and the Petroleum Company of Trinidad & Tobago ("**Petrotrin**") respecting the operations of each of the Central Range Blocks. These joint operating agreements provide Petrotrin with the right to participate for a 35 percent net working interest in any development on the Central Range Shallow Block and for a 20 percent net working interest in any development on the Central Range Deep Blocks. See *Principal Properties – Trinidad & Tobago*.

Work activity on the Central Range Blocks by Parex Trinidad has included:

- a 5,500 linear kilometre airborne geophysical survey;
- two two-dimensional ("**2D**") seismic acquisition programs totalling 274 kilometres of acquired seismic; and
- drilled and completed two exploration wells on the Central Range Shallow Blocks, which were deemed non-commercial.

The Company purchased a performance bond and provided a guarantee to the underwriters of the bond in the amount of $33 million to cover its and Niko's share of the financial guarantees required under the PSCs for the original initial 48-month exploration phase on the Central Range Blocks, which exploration phase was subsequently extended to 72 months. The performance bond terminated on September 19, 2012 and was not extended. In the event of default by Niko, the JVA provides that Niko's working interest shall vest in Parex Trinidad.

On September 18, 2013, Parex Trinidad, as operator of the onshore Central Range Blocks notified the Trinidad & Tobago Ministry of Energy and Energy Affairs that it will relinquish both Central Range Blocks. Parex Trinidad has satisfied the contractual relinquishment obligations as per the requirements of the Central Range Block production sharing contracts.

See *Principal Properties*.

Moruga Block

On September 16, 2009, Parex Trinidad entered into an agreement with Primera Oil and Gas Limited and Primera Energy Resources Ltd. (together, "**Primera**") (the "**Farm In**") to farm in to the interests of these companies in the Moruga Block Exploration and Production Licence located in South Central Trinidad (the "**Moruga Block**"). The terms of the Farm In required Parex Trinidad to drill two exploration wells on the Moruga Block with one well achieving a minimum depth of 10,500 feet and the other to be drilled to a minimum depth of 8,600 feet or to the top of the Cretaceous section. In connection with the Farm In, an application has been made for Parex Trinidad to become the operator of the Moruga Block. The Farm In and transfer of operatorship to Parex Trinidad was subject to approval by the Trinidad & Tobago Ministry of Energy and Energy Affairs (the "**MEEA**") and the Ministry of Finance of the Republic of Trinidad & Tobago.

The Company (through Parex Trinidad) has drilled three wells on the Moruga Block since 2010. On April 27, 2011, Parex Trinidad received written communication from the MEEA that Parex Trinidad has fulfilled the earning commitments for the Moruga Block. Parex Trinidad earned a 50 percent working interest in the Moruga Block by paying 95 percent of all costs, to a maximum of $13.3 million of which $12.6 million was paid**,** for drilling and evaluating the two exploration wells on the Moruga Block. Parex Trinidad also received the assignment of the working interests and the transfer of operatorship from the MEEA in 2012 and continues to re-evaluate follow-up appraisal locations to the Moruga Block Snowcap-1 discovery. Parex Trinidad drilled two additional exploration prospects on the Moruga Block in 2012, both of which were deemed non-commercial.

In June 2012 Parex Trinidad purchased an additional 33.8 percent working interest in the Moruga Block for approximately $10 million, increasing its working interest in the Moruga Block to 83.8 percent.

On August 19, 2013, Parex Trinidad entered into a farm-out agreement for the Moruga Block. Under the terms of the farm-out agreement, the farmee earned a 20 percent participating interest in the Moruga Block after providing Parex Trinidad with a $2 million payment. The farmee, as contract operator will also earn an additional 31 percent participating interest in the block upon completion of: (i) paying 100 percent of Parex Trinidad's costs to work-over Snowcap-1 well and place it on production; (ii) paying 100 percent of Parex Trinidad's costs to drill, complete and test an exploration well within 9 months of the farm-out agreement's effective date; and (iii) paying 100 percent of Parex Trinidad's costs to drill, complete and test a second exploration well within 6 months of the rig release of the first exploration well. If all the Moruga Block farm-out agreement's terms are fulfilled by the farmee, Parex Trinidad will transfer operatorship to the farmee and reduce its participating interest from 83.8 percent to 32.8 percent.

See *Principal Properties*.

Parex Resources (Colombia) Ltd.

Parex Colombia was incorporated on January 8, 2009 under the *Companies Act* of Barbados for the purpose of carrying on oil exploration and development activity in Colombia. Parex Colombia's activities in Colombia are primarily performed through a branch known as Parex Resources Colombia Ltd. Sucursal ("**PACLS**"). A certificate of existence and legal representation was issued by the Cámara de Comercio de Bogota on February 26, 2009 whereby Parex Colombia was able to commence activity in Colombia.

PARI participated in the Colombia Mini Bid Round 2008. Bids were made jointly with Columbus Energy Sucursal Colombia ("**CESC**") under the terms of a Joint Bid and Study agreement. On December 4, 2008 PARI and CESC were jointly the successful bidders for four exploration blocks in the Llanos Basin – Block LLA-16 ("**Block LLA-16**"), Block LLA-20 ("**Block LLA-20**"), Block LLA-29 ("**Block LLA-29**") and Block LLA-30 ("**Block LLA-30**" and collectively with Block LLA-16, Block LLA-20 and Block LLA-29, the "**2008 Blocks**").

On January 30, 2009, PARI and CESC signed joint venture agreements ("**Acuerdo Union Temporal**") for each of the 2008 Blocks with each partner having a 50 percent interest. Subsequently, on March 11, 2009, PARI and CESC amended the Acuerdo Union Temporal for each of the 2008 Blocks to reflect Parex Colombia as the operating entity in Colombia instead of PARI.

On April 20, 2009, exploration and production contracts ("**E&P**" **Contracts**") for the 2008 Blocks were finalized between the Agencia Nacional de Hidrocarburos ("**ANH**"), and Parex Colombia and CESC. Pursuant to the contracts, on July 14, 2009, Parex Colombia and CESC each provided guarantees to ANH in the form of letters of credit in respect of a portion of the work commitments for Block LLA-16 and Block LLA-20. Guarantees to the ANH for Block LLA-29 and Block LLA-30 were provided on November 5, 2009.

On June 29, 2011, Parex Colombia acquired the 50 percent interest of CESC in the 2008 Blocks through the acquisition of Subco pursuant to the Remora Acquisition. As a result, Parex Colombia holds a 100 percent interest in the 2008 Blocks and assumed the letters of credit to the ANH in respect of the additional 50 percent of the work commitments for the 2008 Blocks.

On July 21, 2010, the Company was advised by the ANH that it was the successful bidder for a 100 percent interest in Block LLA-57 in the Llanos Basin. On February 11, 2011, Parex Colombia, through PACLS, finalized the E&P Contract for Block LLA-57. Block LLA-57 covers 104,532 gross acres and is located north and adjacent to Block LLA-20. The Company provided a guarantee to the ANH for Block LLA-57.

On June 22, 2011, PACLS signed a farm-in agreement with Petroamerica Oil Corp. ("**Petroamerica**") for the Los Ocarros Block (the "**Los Ocarros Block**") pursuant to which PACLS is required to fund 100 percent of the drilling costs associated with the Las Maracas-2 sidetrack well located on the Los Ocarros Block to a maximum of $7 million. PACLS fulfilled the farm-in commitment and thereby earned a 50 percent interest in the Las Maracas discovery located on the Los Ocarros Block and a 25 percent interest in the balance of the Los Ocarros Block. The Los Ocarros Block is located directly southwest of Block LLA-16. The Los Ocarros farm-in was subject to regulatory approval, which was received in December 2012. See *Principal Properties*.

On September 23, 2011, PACLS signed a farm-in agreement with Petroamerica in respect of the El Eden Block, which Block is located south-west of Block LLA-16 and the Los Ocarros Block in the Llanos Basin. The farm-in, which excluded the Chiriguaro oil discovery area, was subject to approval by the ANH which was received in December 2012. Under the terms of the farm-in, PACLS paid $3.5 million for reimbursement of prior 3-D seismic costs and funded the first 65 percent of an exploratory commitment well, La Casona-1, which was drilled in September 2012 and thereby earned a 35 percent working interest in the El Eden Block. PACLS will be the operator of the exploratory commitment well. In January 2012 PACLS entered into an agreement to purchase an additional 25 percent interest in the El Eden Block from Talisman, subject to regulatory approval, which was received. After fulfilling the terms of the farm-in agreement and closing the purchase of the additional 25 percent working interest, PACLS has a 60 percent working interest in the El Eden Block and a 50 percent working interest in the non-producing Chiriguaro oil discovery located in the El Eden Block.

On March 16, 2012, Parex Colombia entered into a farm-in agreement with Cepsa Colombia S.A. ("**Cepsa**") for the Cabrestero Block requiring PACLS to pay 100 percent of the drilling costs associated with the Kitaro-1 exploration well to earn a 50 percent interest in the Cabrestero Block. PACLS fulfilled the farm-in commitment in July 2012 and received ANH recognition of the farm-in and as operator of the Cabrestero Block in December 2012.

On June 22, 2013, Parex signed a purchase agreement to acquire an 80% working interest and operatorship in the LLA-26 block in the Llanos Basin of Colombia (the "**LLA-26 Block**") for total consideration of $1 million. Further, Parex signed a farm-in agreement in respect of the remaining 20% working interest in the LLA-26 Block. Pursuant to the terms of the farm-in agreement, Parex pays 100% of the working interests costs for the drilling of one exploration well to a depth of approximately 12,000 feet. Both the purchase and the farm-in are subject to regulatory approval.

On July 9, 2013, Parex signed a farm-in agreement for the VMM-11 Block in the Middle Magdalena Basin of Colombia. Pursuant to the terms of the farm-in agreement, Parex will pay 100 percent of one exploration well and 20 km2 of 3D seismic to earn 60 percent working interest and operatorship, subject to regulatory approval. The VMM-11 Block is approximately 117,000 gross acres and subject to an initial base royalty of 9 percent.

On July 26, 2013, Parex completed the purchase of its partner's 50 percent working interest in the Morpho Block in return for a 4 percent net profit interest royalty, subject to regulatory approval. The Morpho Block is located in the Middle Magdalena Basin of Colombia near the VMM-11 Block.

On August 1, 2013, Parex signed an assignment agreement for 100 percent working interest and operatorship of the Cebucan Block in the Llanos Basin of Colombia. Pursuant to the terms of the agreement, at the assignment of such working interest by the regulator, Parex will pay $4.5 million. The current exploration phase requires drilling one exploration well.

On October 24, 2013, Parex signed a farm-in agreement for the LLA-24 Block in the Llanos Basin of Colombia. Pursuant to the terms of the farm-in agreement, Parex receives a 70 percent working interest, operatorship and has a commitment to pay 100 percent of the drilling of one exploration well to a depth of approximately 8,000 feet, subject to regulatory approval.

On February 12, 2014, Parex signed a farm-in agreement for the exploration area of the El Porton block in the Llanos Basin of Colombia (the "**El Porton Block**"). Pursuant to the terms of the farm-in agreement, Parex will pay 80 percent of the dry hole cost of one exploration well to earn a 50 percent working interest and operatorship, subject to regulatory approval. The exploration area of the El Porton Block is approximately 109,000 gross acres and subject to an initial base royalty of 8 percent.

See *Principal Properties*.

Parex Energy Colombia Ltd.

Subco was incorporated on May 7, 2007 under the *Companies Act* of Bermuda for the purpose of carrying on oil exploration and development activity in Colombia. On June 29, 2011, Parex Colombia acquired the Acquired Assets, which included the 50 percent interest of CESC in the 2008 Blocks through the acquisition of Subco pursuant to the Remora Acquisition. On September 21, 2011, Subco was continued out of the jurisdiction of Bermuda and into the jurisdiction of Barbados and renamed Parex Energy Colombia Ltd. The interests of Subco are operated by PACLS. Effective June 28, 2013, Subco was amalgamated with Parex Colombia.

See *General Development of the Business – History of the Company* and *Principal Properties*.

Parex Resources (Bermuda) Ltd.

Parex Bermuda was incorporated on April 9, 2012 under the *Companies Act* of Bermuda. Parex Bermuda does not directly own any operating oil or natural gas assets. Parex Bermuda owns all of the class A shares of Ramshorn as acquired by Parex Bermuda pursuant to the Ramshorn Acquisition, which occurred on April 12, 2012, Parex Bermuda also facilitates the capitalization and growth of the Company's other subsidiaries.

See *General Development of the Business – History of the Company* and *Principal Properties*.

Ramshorn International Limited

Ramshorn was incorporated on November 3, 2003 under the *Companies Act* of Bermuda for the purpose of carrying on oil exploration and development activity in Colombia. On April 12, 2012 Parex Bermuda acquired the class A shares of Ramshorn pursuant to the Ramshorn Acquisition. In addition to class A shares, Ramshorn has issued and outstanding class B shares, all of which are owned by a third party entity, Shona Energy International Limited, which class B shares were issued in connection with a joint venture for certain oil and gas interests in Peru in which Ramshorn has no economic interest. Ramshorn and Parex Bermuda, on the one hand, and Shona Energy International Limited, on the other, have indemnified each other so that the Ramshorn class A shares derive no economic benefits or liabilities associated with the class B shares and the Peru joint venture and the class B shares derive no economic benefits or liabilities of the Colombia operations.

The primary assets of Ramshorn currently consist of working interests in exploration contracts for Llanos Basin Blocks, LLA-32 and LLA-34.

See *General Development of the Business – History of the Company* and *Principal Properties*.

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including in Trinidad & Tobago, Colombia and Canada where the Company's assets, activities, and employees are located. Operators more established than the Company, with access to broader technical skills, larger amounts of capital and other resources, are active in the industry in all three countries in which the Company has operations. This represents a significant risk for the Company, which must rely on modest resources as compared to some of its competitors. See *Risk Factors*.

Risks of Foreign Operations

All of the Company's oil and natural gas operations occur outside of Canada and therefore are subject to political and regulatory risk in those other jurisdictions. In addition, the Company has established an Anti-Bribery and Anti-Corruption Policy. See *Risk Factors*.

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Company or any of its Subsidiaries, or any voluntary bankruptcy, receivership or similar proceeding by the Company or any of its Subsidiaries, within the three most recently completed financial years or during or proposed for the current financial year.

Reorganizations

There have been no material reorganizations of the Company or any of its Subsidiaries within the three most recently completed financial years or during or proposed for the current financial year, except for the amalgamation of Subco with Parex Colombia. See *Corporate Structure – Intercorporate Relationships*.

Employees

The following table details the Company's employees as of December 31, 2013, 2012 and 2011:

	Number of Employees		
	Dec. 2013	**Dec. 2012**	**Dec. 2011**
Calgary	39	30	30
Colombia	154	137	80
Trinidad	13	17	12
Total	**206**	**184**	**122**

Environmental Protection

The Company operates under the jurisdiction of a number of regulatory bodies and agencies in each of the jurisdictions in which it operates that set forth numerous prohibitions and requirements with respect to planning and approval processes related to land use, sustainable resource management, waste management, responsibility for the release of presumed hazardous materials, protection of wildlife, and the environment and the health and safety of workers. Legislation provides for restrictions and prohibitions on the transport of dangerous goods and the release or emission of various substances, including substances used and produced in association with certain oil and gas industry operations. The legislation addresses various permits, including for drilling, well completion, installation of surface equipment, air monitoring, surface and ground water monitoring in connection with these activities, waste management and access to remote or environmentally sensitive areas.

Historically, environmental protection requirements have not had a significant financial or operational effect on Parex' capital expenditures, earnings or competitive position. Subject to any changes in current environmental protection legislation, or in the way the legislation is interpreted in the jurisdictions in which it operates, Parex does not presently anticipate environmental protection requirements will have a significant effect on such matters in 2014. The Company is exposed to potential environmental liability in connection with its business of oil and gas exploration and production. See *Risk Factors*.

Trends in Environmental Regulation

The Company is of the opinion that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Company anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect the Company's financial condition, capital expenditures, results of operations, competitive position or prospects. See *Risk Factors.*

Social or Environmental Policies

Environment, Health and Safety Policies and Procedures

The Company's main environmental strategies include the preparation of comprehensive environmental impact assessments and assembling project-specific environmental management plans. Parex encourages local community engagement in environmental planning in order to create a positive relationship between the oil business and existing local industries. The Company's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. Parex is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Monitoring and reporting programs for environment, health and safety ("**EH&S**") performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. The Company maintains an active comprehensive integrity monitoring and management program for its facilities, storage tanks and pipelines. The Company's practice is to not dispose of produced water above ground. Contingency plans are in place for a timely response to an environmental event and abandonment, remediation and reclamation programs are in place and utilized to restore the environment. The Company also performs a detailed due diligence review as part of its acquisition process to determine whether the assets to be acquired are in regulatory and environmental compliance and assess any liabilities with respect thereto. Parex expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2013, expenditures for normal compliance with environmental regulations, as well as expenditures beyond normal compliance, were not material.

Management is responsible for reviewing the Company's internal control and its EH&S strategies and policies, including the Company's emergency response plan. Management reports to the Board of Directors through the Operations and Reserves Committee of the Board of Directors on a quarterly basis with respect to EH&S matters, including: (i) compliance with all applicable laws, regulations policies with respect to EH&S; (ii) on emerging trends, issues and regulations that are relevant to the Company; (iii) the findings of any significant report by regulatory agencies, external health, safety and environmental consultants or auditors concerning performance in EH&S; (iv) any necessary corrective measures taken to address issues and risks with regards to the Company's performance in the areas of EH&S that have been identified by Management, external auditors or by regulatory agencies; (v) the results of any review with management, outside accountants, external consultants and legal advisors of the implications of major corporate undertakings such as the acquisition or expansion of facilities or ongoing drilling and testing operations, or decommissioning of facilities; and (vi) all incidents and near misses with respect to the Company's operations, including corrective actions taken as a result thereof.

Community Relations

The Company has developed a series of policies and practices that complement its basic responsibilities as a development tool for the local communities in the jurisdictions in which it operates. Parex' corporate social responsibility strategy is based on the following main principles:

- creating local employment opportunities, both within the oil industry and within existing local industries;
- providing education and training programs to strengthen community and local authority relationships, while identifying new markets for local goods and services, and reducing dependence on industry support; and
- engaging communities in studies and processes related to environmental management by combining the Company's expertise with local knowledge.

The Company's efforts have been well received by the local communities and has contributed to maintaining a positive relationship in and around the Company's operations.

PRINCIPAL PROPERTIES

As at December 31, 2013, the Company's principal land holdings and exploration blocks were as follows:

	Working Interest	**Gross Acres[1]**	**Net Acres[2]**	**Parex 2013 Annual Production (bopd)**
Colombia Llanos Basin				
Operated Properties				
Block LLA-16	100%	157,610	157,610	5,100
Block LLA-20	100%	144,290	144,290	539
Block LLA-24[3]	70%	147,100	102,970	-
Block LLA-26[3]	80%	184,061	147,249	-

	Working Interest	Gross Acres(1)	Net Acres(2)	Parex 2013 Annual Production (bopd)
Block LLA-29	100%	69,915	69,915	-
Block LLA-30	100%	117,322	117,322	463
Block LLA-57	100%	104,532	104,532	-
Los Ocarros Block	50%	110,436	55,218	5,266
Block LLA-17	40%	108,726	43,490	54
El Eden Block	60%	109,249	65,549	41
Cabrestero Block	100%	29,562	29,562	476
Block LLA-40	50%	163,090	81,545	-
Cebucan Block(3)	100%	109,150	109,150	-
Non-Operated Properties				
Block LLA-32	30%	100,325	30,097	445
Block LLA-34	45%	82,286	37,029	3,470
Colombia Middle Magdelena				
Operated Properties				
VMM-11 Block(3)	60%	116,826	70,096	-
Morpho(3)	100%	51,398	51,398	-
Trinidad &Tabago				
Non-Operated Properties				
Moruga Block(4)	63.8%	7,443	4,749	-
Total		1,913,321	1,421,771	15,854

Notes:

(1) "Gross" means acres in which the Company has an interest.
(2) "Net" means the Company's interest in the gross acres.
(3) Lands are subject to farm-in agreement earning terms and/or regulatory approval.
(4) Moruga Block subject to a farm-out agreement whereby Parex will reduce its working interest to 32.8% upon completion of drilling two wells on the Snowcap discovery and recompleting the Snowcap well by the farmee.

Exploration properties that are deemed non-commercial will be released in due course. Accordingly, the gross versus net acres described above may decrease over time as lands deemed non-commercial are released.

Colombia

A three year summary of the Company's significant producing properties is provided below.

Block LLA-16 (100% working interest)

The principal property on Block LLA-16 is the Kona oil field ("**Kona**"). Kona was discovered by Parex Colombia in May 2010 and placed on production in December 2010. Kona produces from four formations at depths of 11,000 feet to 13,250 feet. Kona's average oil production for 2013 was 4,532 bbl/d (2012 7,953 bbl/d). The oil production from Kona is considered light crude oil and density ranges from 30º to 35º API. Crude oil from Kona is sold to various parties and is primarily used as a diluent to mix with heavy oil production for pipeline transportation to export locations. Kona produced fluid is treated on site through a 75,000 bfpd facility and associated water disposal wells. The Kona field's cumulative oil production exceeded 5 million bbls in January 2013 and, as a result, the royalty for the Kona development area has increased to approximately 30% from 9%, as specified in the terms of the 2008 ANH contracts.

The other primary producing property on Block LLA-16 is the adjoining Sulawesi and Malawi fields. The Sulawesi field was discovered by Parex Colombia in 2011 and is located approximately seven kilometres south of the Kona field. In 2012 Parex commenced drilling in the Malawi field located directly south of the Sulawesi field and brought this production into the Sulawesi facility. The Sulawesi and Malawi fields produce light oil from two formations with production averaging 436 bbl/d in 2013 (2012 442 bbl/d). Sulawesi and Malawi crude oil density is approximately 30º API and is sold as diluent.

The Java field was discovered in 2012 mid way between the Kona and Sulawesi fields. Currently two wells have been drilled into the structure and facilities have been installed. Production averaged 132 bbl/d in 2013 as the Java field remained shut in for much of 2013 as Parex focussed its operations on larger opportunities. Parex expects to restart production in the Java field during 2014.

Block LLA-20 (100% working interest)

The Conoto-1 and Zocay-1 wells were drilled in late 2010 to early 2011, with the Conoto-1 well being rig released in 2010 and the Zocay-1 well released in early 2011. The log response on the Conoto-1 well was ambiguous, so the well was cased for testing. Testing of the Conoto-1 well recovered a small amount of heavy oil from the Mirador formation but all other zones were water bearing. Based on the testing results from Conoto-1, the Zocay-1 well was drilled and abandoned without testing, on the basis of well log evaluation.

In March 2012, the Company discovered the Cumbre field with the successful test of the Cumbre-1 well. Three additional wells, including a water disposal well, were drilled at the Cumbre field in 2012. In 2013, an additional well was drilled into the Cumbre Sur prospect which was unsuccessful and converted to water disposal to allow handling of larger produced water volumes at Cumbre. Average oil production for 2013 was 538 bbl/d (for 2012, 614 bbl/d). The Cumbre field crude density is approximately 31º API and is produced at a depth of approximately 9,000 feet.

Block LLA-30 (100% working interest)

In early 2013, the Vivania Este-1, Adalia Norte-1 and Adalia-1 wells were drilled. Vivania Este-1 and Adalia Norte-1 were both tested and suspended. Parex anticipates re-evaluating both wells in 2014 using a service rig. Adalia-1 was brought on-stream in March 2013 and average oil production for 2013 was 900 bbl/d of 38º API at a depth of approximately 5,300 feet. During the fourth quarter of 2013, Adalia-2 and Adalia-3 were drilled. Adalia-3 was completed for production in early 2014 and Adalia-2 will be tested during 2014.

Los Occaros Block (50% working interest)

In 2011, PACLS farmed into the Los Ocarros Block and drilled the Las Maracas-2 side track to earn a 50% interest in the Los Ocarros Block. The well was cased and the top of the Mirador interval from 12,483 to 12,489 ft was perforated and tested. The well tested under natural flow conditions at rates up to 938 bopd with a final rate, after a 22 hour flow period, of 867 bopd at a water cut of 0.8%. During 2012, Parex and its partner drilled seven wells at Las Maracas targeting extension of the Mirador reservoir, which also discovered oil in the Gacheta and Une reservoirs. In 2013, an additional seven wells were drilled to exploit the Mirador, Gacheta and Une reservoirs resulting in six producing wells and one disposal well. Average net oil production for 2013 was 5,266 bbl/d net (10,532 bbl/d gross). Production for the period from October 1, 2013 to December 31, 2013 increased to average 6,177 bbl/d net (12,354 bbl/d gross) due to successful appraisal drilling. The Company believes the Las Maracas field is close to fully developed and has one well planned for 2014.

Cabrestero Block (100% working interest)

In 2012, PACLS farmed into the Cabrestero Block and drilled the Kitaro-1 well to earn a 50% interest in the block. The well was cased and initially tested in the Une formation. In August of 2012, the Kitaro-1 well was recompleted in the Mirador formation as the temporary facility did not have capacity to handle increasing water production from the Une formation. The Kitaro-2 well was drilled as a follow-up well and was produced over a two week period from the Guadalupe formation at an average rate of 200 bbl/d net (400 bbl/d gross) until water breakthrough, at which point the well was recompleted in the Mirador formation. In 2012, the Akira prospect was drilled from the Kitaro location to test the Guadalupe formation at a depth of 9,500 feet. The Akira-1 well was placed on production from the Guadalupe formation and produced at rates of 300-400 bbl/d.

On May 31, 2013, Parex completed the purchase of its partner's 50 percent working interest in the Cabrestero Block for $12.5 million before adjustments. Beginning in April of 2013, Parex continued appraisal of the Akira field by drilling wells Akira-2 through Akira-6 which expanded the size of this field, and allowed Parex to commit to a large Oil Treatment Plan ("**OTP**") expansion which is expected to be commissioned in second quarter of 2014. Delineation of the Akira field will continue in 2014 to define the ultimate limits of the field.

Average net oil production for the block in 2013 was 322 bbl/d net (476 bbl/d gross) as the Akira and Kitaro fields remained shut in for most of 2013 and into 2014 waiting final facility installation. The Kitaro field crude density is 20º API, while the Akira field crude density is 15º API.

Block LLA-34 (45% working interest)

Parex obtained its 45 percent interest in block LLA-34 ("**Block LLA-34**") through the purchase of the class A shares of Ramshorn by Parex Bermuda in April 2012. This block is adjacent to Block LLA-32 (see below). During 2012, Parex and its partners drilled the Tua prospect and made a discovery in the Guadalupe and Mirador reservoirs. Two additional follow up wells were successfully drilled and placed on production at Tua, and a water disposal well was drilled at Max field. In 2013, an additional three delineation wells were drilled at Tua, which were all placed on production. Parex and its partners also discovered the Tigana and Tarotaro reservoirs in 2013, drilling a total of four wells in Tarotaro and two wells in Tigana. Both fields are productive in the Guadalupe and Mirador reservoirs and produce oil of 15º to 20º API. In 2014, Parex and its partners plan to delineate the Tigana, Tua, Tarotaro and Max reservoirs further, while expanding facilities at all fields.

Average net oil production for Block LLA-34 in 2013 was 3,470 bbl/d net (7,711 bbl/d gross). Production in the period from October 1, 2013 to December 31, 2013 increased to average 4,863 bbl/d net (10,808 bbl/d gross), primarily due to the successful exploration and appraisal drilling.

The Company expects to drill up to 11 appraisal/development/exploration wells in LLA-34 in 2014.

Block LLA-32 (30% working interest)

Parex obtained its 30% interest in Block LLA-32 through the purchase of the class A shares of Ramshorn by Parex Bermuda in April 2012. Block LLA-32 is immediately north of the Cabrestero Block and south of Block LLA-34. Block LLA-32 was producing from the Maniceno field and in 2013 Parex and its partners drilled a second successful well in the field. Average net oil production for the Maniceno field in 2013 was 543 bbl/d net (1,743 bbl/d gross). The Maniceno field crude density is approximately 26º API and produces from the Mirador formation at approximately 11,000 feet.

Summary of Block Commitments as of March 18, 2014

Blocks	**Exploration Phase**	**Current Phase Expiry Date**	**Outstanding Letter of Credit (LC)[1]**	**Current Commitment**
LLA-16	Phase 2 (current)	July 1, 2015	$500,000	2 exploratory wells (done)
LLA-20	Phase 2 (current)	July 28, 2015	$500,000	2 exploratory wells
LLA-24	Phase 1 (current)	January 23, 2016	$310,000	Seismic + 2 exploratory well
LLA-29	Phase 1 (current)	April 27, 2014	$9,887,500	Seismic (done) + 5 exploratory wells

Blocks	Exploration Phase	Current Phase Expiry Date	Outstanding Letter of Credit (LC)[1]	Current Commitment
LLA-30	Phase 1 (current)	May 19, 2014	$5,000,000	Seismic (done) + 3 exploratory wells (done)
	Phase 2 (current)	November 19, 2016	$500,000	2 exploratory wells
LLA-57	Phase 1 (current)	March 22, 2014	$300,000	Seismic (done) + 2 exploratory wells
	Phase 1 (current)	March 22, 2014	$1,500,000	Seismic (done) + 2 exploratory wells
Cabrestero	Phase 4 (current)	January 24, 2014	$1,000,000	Operatorship transfer, release requested
El Eden	Phase 4&5 (current)	January 10, 2014	$1,650,000	Operatorship transfer, release requested
	Phase 4&5 (current)	June 20, 2014	$660,000	2 exploratory wells
	Phase 1 PEP[2]	November 13, 2015	$330,000	1 exploratory well
Los Ocarros	Phase 5 (current)	June 12, 2014	$275,000	1 exploratory well (done)
	Phase 1 PEP	November 13, 2015	$275,000	1 exploratory well
LLA-17	Phase 2 (current)	September 13, 2015	$532,000	2 exploratory wells (done)
LLA-32	Phase 2 (current)	August 20, 2015	$450,000	Seismic (done) + 2 exploratory wells (done)
LLA-34	Phase 2 (current)	September 10, 2015	$711,000	2 exploratory wells (done)
LLA-40	Phase 1 (current)	June 14, 2014	$150,000	Seismic (done) + 4 exploratory wells
	Phase 1 (current)	June 14, 2014	$4,550,000	Seismic (done) + 4 exploratory wells
VMM-11	Phase 1 (current)	September 15, 2014	$1,200,000	Seismic + 1 exploratory well
Total			**$30,280,500**	

Note:

(1) Parex on behalf of its Colombian branches have provided guarantees to the ANH which currently total approximately $30.3 million related to work commitments in respect of the Company's exploration acreage. The guarantees have been provided in the form of letters of credit for up to 36-month terms. Parex has outstanding letters of credit for each block, except for Morpho. An estimated $10.1 million of work commitments have been performed and the Company expects to have the existing letters of credit reduced by such amount. EDC has provided the Company's bank with performance security guarantees to support the letters of credit issued on behalf of Parex, as at the date of this Annual Information Form.

(2) Posterior Exploratory Program.

Trinidad & Tobago

Parex Trinidad has the right to explore for hydrocarbons in the Southern Basin of onshore Trinidad. As at December 31, 2013, Parex Trinidad had an interest in the Moruga Block.

Currently, Parex Trinidad has no oil and natural gas production or oil and natural gas reserves.

Moruga Block

Parex Trinidad holds an 83.3 percent working interest in the on-shore Moruga Block with Primera Energy Resources Ltd ("**Primera**"), holding the balance of the working interest. Parex Trinidad is the operator of the block, which was originally granted on August 29, 2007.

The term of the exploration phase of the Moruga Block is for six years from August 27, 2007 to August 27, 2013. At the end of the sixth year, all acreage not considered to be part of a commercial discovery, as defined in the Moruga Block licence (the "**Moruga Block License**") must be relinquished. For all fields considered to be a commercial discovery the Moruga Block Licence will be extended for a term of 25 years from August 27, 2007. At the end of the 25-year term, the Moruga Block Licence allows for renewal periods of five years at time, based on terms to be negotiated at that time. Undeveloped land deemed non commercial is expected to be released in due course.

Under the terms of the Moruga Block Licence, Parex Trinidad will be subject to royalties, the Petroleum Production Levy, Supplemental Petroleum Tax, the Green Fund Levy, Unemployment Levy and Petroleum Profits tax (refer to *Industry Conditions* for more information in respect of these royalties and levies). The Moruga Block Licence also sets out requirements for various other annual payments such as lease rentals, training, research and development, and scholarships. Production bonuses will be required if average daily production levels reach certain targets, starting with a $1.5 million bonus if production from the Moruga Block reaches 25,000 bbls/d.

Parex Trinidad has drilled three exploration wells on the Moruga Block. Firecrown-1 reached a total measured depth of 10,330 feet but could not be completed and tested due to down-hole conditions. It was subsequently re-drilled in 2012 but tested non commercial amounts of oil and has been abandoned. Snowcap-1 was drilled and cased in the third quarter of 2010 to a depth of 8,600 feet. Parex commenced testing the well in early December, 2010. The Snowcap-1 well tested the primary Herrera zone (4,590-4,605 feet) in a multi-point test over the perforated interval at 4,597-4,603 feet. The final four day test gross rate averaged 580 bopd of 35º API oil and 5.4 mmscfd, with wellhead pressure of 600 psi on a 48/64th inch choke under natural flow. In 2012, the Green Hermit-1 well was drilled to a measured depth of approximately 7,700 feet. Due to the poor testing results at Firecrown-1, the Green Hermit-1 well remains standing, untested.

On August 19, 2013, Parex Trinidad entered into a farm-out agreement for the Moruga Block in Trinidad. Under the terms of the farm-out agreement, the farmee earned a 20 percent participating interest in the Moruga Block after providing Parex Trinidad with a $2 million payment. The farmee, as contract operator, will also earn an additional 31 percent participating interest in the block upon completion of: (i) paying 100 percent of Parex Trinidad’s costs to work-over the Snowcap-1 well and place it on production; (ii) paying 100 percent of Parex Trinidad’s costs to drill, complete and test an exploration well within 9 months of the farm-out agreement's effective date; and (iii) paying 100 percent of Parex Trinidad’s costs to drill, complete and test a second exploration well within 6 months of the rig release of the first exploration well. If all the Moruga Block farm-out agreement terms are fulfilled by the farmee, Parex Trinidad will transfer operatorship to the farmee and reduce its participating interest from 83.8 percent to 32.8 percent.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Reserves Data**") is dated December 31, 2013. The effective date of the Reserves Data is December 31, 2013 and the preparation date of the Reserves Data is February 20, 2014. All of the Company's reserves are located in Colombia.

Disclosure of Reserves Data

The reserves data set forth below are based upon an evaluation by GLJ set out in the GLJ Report dated February 20, 2014 with an effective date of December 31, 2013. The Reserves Data summarize the oil reserves of the Company and the net present values of future net revenue for such reserves using forecast prices and costs as at December 31, 2013. All of the Company's oil production and oil reserves are located in the Llanos Basin of Colombia. Currently, Parex Trinidad has no oil production or booked oil reserves. **The Company does not have any heavy oil, coalbed methane or NGL production or reserves and has an immaterial amount of natural gas reserves and did not have any natural gas production in the year ended December 31, 2013.**

The reserve estimates presented in the GLJ Report are based on the guidelines contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth in the glossary to this Annual Information Form. GLJ was engaged to provide evaluations of proved reserves, proved plus probable reserves and proved plus probable plus possible reserves. Additional information not required by NI 51-101 has been presented to provide continuity and clarity which the Company believes is important to the readers of this information.

The Operations and Reserves Committee of the Board of Directors has reviewed and approved the GLJ Report. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator or Auditor are attached as Schedules "A" and "B" hereto, respectively.

All evaluations of future revenue contained in the GLJ Report 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 estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of crude oil, reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the reserves provided herein are estimates only, and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. See *Risk Factors*.

In general, estimates of economically recoverable crude oil reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development, and operating expenditures with respect to the reserves associated with the Company's properties may vary, from the information presented herein, and such variations could be material. In addition, there is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained, and variances could be material. See *Forward Looking Statements* and *Risk Factors*.

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

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

In certain of the tables set forth below, the columns may not add due to rounding. All dollar amounts expressed in the tables below are expressed in United States dollars.

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2013
FORECAST PRICES AND COSTS

Reserve Category	Light and Medium Oil		Total Oil Equivalent[2]	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED				
Developed Producing	7,681	6,495	7,795	6,600
Developed Non-Producing	1,111	922	1,111	922
Undeveloped	8,363	7,091	8,462	7,184
TOTAL PROVED	17,155	14,508	17,368	14,707
PROBABLE	14,270	11,718	14,653	12,075
TOTAL PROVED PLUS PROBABLE	31,424	26,227	32,021	26,782
POSSIBLE	17,570	13,813	17,927	14,149
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	48,994	40,040	49,949	40,931

Notes:

(1) "Gross Reserves" are the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves. See *Certain Definitions*.

(2) Total oil equivalent includes an immaterial amount of natural gas reserves for each reserves category.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2013
FORECAST PRICES AND COSTS

Reserves Category	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/ year[1]
	0 ($000's)	5 ($000's)	10 ($000's)	15 ($000's)	20 ($000's)	0 ($000's)	5 ($000's)	10 ($000's)	15 ($000's)	20 ($000's)	($/boe)
PROVED											
Developed Producing	364,368	347,307	332,236	318,816	306,779	328,710	313,193	299,495	287,305	276,377	50.34
Developed Non-Producing	43,552	38,313	34,183	30,860	28,136	38,276	33,516	29,736	26,676	24,158	37.06
Undeveloped	339,476	300,793	269,071	242,711	220,550	224,556	196,478	173,590	154,686	138,887	37.45
TOTAL PROVED	747,396	686,413	635,490	592,387	555,465	591,542	543,187	502,822	468,667	439,422	43.21
PROBABLE	684,297	582,698	505,245	444,714	396,389	455,462	383,787	329,556	287,488	254,145	41.84
TOTAL PROVED PLUS PROBABLE	1,431,693	1,269,111	1,140,735	1,037,101	951,854	1,047,004	926,973	832,378	756,156	693,567	42.59
POSSIBLE	885,589	706,042	582,558	493,630	427,092	592,184	466,933	381,535	320,552	275,290	41.17
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	2,317,282	1,975,153	1,723,293	1,530,730	1,378,946	1,639,187	1,393,906	1,213,913	1,076,708	968,857	42.10

Notes:

(1) The unit values are based on net reserve volumes.

(2) Net present values prepared by GLJ in the evaluation of Parex' oil properties are calculated by considering sales of oil, reserves, processing of third party reserves and other income. After tax net present values prepared by GLJ in the evaluation of Parex' oil properties are calculated by considering the foregoing factors, as well as appropriate income tax calculations, current federal tax regulations, and by including prior tax pools for Parex.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2013
FORECAST PRICES AND COSTS

Reserves Category	Revenue ($000's)	Royalties ($000's)	Operating Costs ($000's)	Development Costs ($000's)	Abandonment and Reclamation Costs ($000's)	Future Net Revenue Before Future Income Taxes ($000's)	Future Income Taxes ($000's)	Future Net Revenue After Future Income Taxes ($000's)
Proved Reserves	1,437,576	222,987	303,860	147,188	16,144	747,396	155,854	591,542
Proved Plus Probable Reserves	2,615,915	433,210	498,469	232,398	20,144	1,431,693	384,689	1,047,004
Proved Plus Probable Plus Possible Reserves	4,084,633	744,633	693,480	305,467	23,770	2,317,282	678,095	1,639,187

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP[2]	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000's)	UNIT VALUE ($/boe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	635,490	43.21
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	1,140,735	42.59
Proved Plus Probable Plus Possible	Light and Medium Crude Oil (including solution gas and other by-products)	1,723,293	42.10

Note:

(1) The unit values are based on net reserve volumes.

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2013, reflected in the Reserves Data. These price assumptions were provided to Parex by GLJ and were GLJ's then current forecast at the date of the GLJ Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS(1)
as at December 31, 2013
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	ICE Brent	Medium Crude Oil 29° API ($Cdn/bbl)	Hardisty Heavy 12° API ($Cdn/bbl)	Inflation Rates(2) (%/Year)	Exchange Rate(3) ($US/$Cdn)
2013	97.88	108.76	88.05	65.07	1.0	0.971
Forecast(4)						
2014	97.50	107.50	86.27	65.72	2.0	0.95
2015	97.50	107.50	90.55	70.03	2.0	0.95
2016	97.50	105.00	93.00	72.85	2.0	0.95
2017	97.50	102.50	93.00	72.85	2.0	0.95
2018	97.50	102.50	93.00	72.85	2.0	0.95
2019	97.50	102.50	93.00	72.85	2.0	0.95
2020	98.54	102.50	93.71	73.42	2.0	0.95
2021	100.51	103.38	95.58	74.90	2.0	0.95
2022	102.52	105.45	97.49	76.42	2.0	0.95
2023	104.57	107.56	99.44	77.97	2.0	0.95
Thereafter				Escalated oil, gas and product prices at 2% per year thereafter.		

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) The exchange rate used to generate the benchmark reference prices in this table.
(4) As at December 31.

Average historical prices for the year ended December 31, 2013, were $US108.64/bbl for crude oil at ICE Brent.

Reserves Reconciliation

The following table sets forth a reconciliation of the Company's total gross proved, gross probable and total gross proved plus probable oil reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on forecast prices and cost assumptions. All of the Company's evaluated reserves are located in Colombia.

	Light And Medium Oil(1)		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2012	10,063	6,037	16,100
Extensions	4,117	2,475	6,592
Improved Recovery	-	-	-
Infill Drilling	-	-	-
Technical Revisions	3,933	(572)	3,360
Discoveries	4,187	5,722	9,909
Acquisitions	632	608	1,240
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(5,777)	-	(5,777)
December 31, 2013	17,155	14,270	31,425

Note:

(1) The Company has not presented a reserves reconciliation for total oil equivalent reserves. Such reconciliation would include an immaterial amount of natural gas reserves since December 31, 2012, being 1,282 MMcf of natural gas

reserves (231 Mboe) in the proved category and 2,298 MMcf natural gas reserves (596 Mboe) in the proved plus probable category.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ 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. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101.

In general, the Company plans to develop all of the proved undeveloped reserves over the next two years. In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see *Risk Factors* herein.

Proved and Probable Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Parex' assets for the years ended December 31, 2013, 2012 and 2011 and, in the aggregate, before that time based on forecast prices and costs. All of the Company's proved undeveloped reserves and the probable undeveloped reserves are located in Colombia. See *Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data*.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)(1)	
	First Attributed	Cumulative at Year End
Prior thereto	633	633
2011	1,667	1,667
2012	2,981	4,096
2013	5,032	8,363

Note:

(1) The GLJ Report also attributes to Parex' assets for the year ended December 31, 2013, an immaterial amount of proved undeveloped natural gas reserves of 559 MMcf (first attributed) and 596 MMcf (cumulative at year-end). No proved undeveloped natural gas reserves were attributed for the years ended December 31, 2012 and 2011 or prior thereto.

The GLJ Report disclosed Company gross proved undeveloped reserves of 8,363 mbbl before royalties. These are reserves which can be estimated with a high degree of certainty to be recoverable, provided a significant expenditure is made to render them capable of production. The Company believes it has or will have capital spending plans in place during 2014 and 2015 to drill the necessary locations and to construct the necessary facilities to permit these proved undeveloped reserves to be reclassified as proved developed reserves. These expenditures are reflected in the future development costs disclosed herein. The undeveloped reserves are expected to be significantly developed within the next two years. See *Principal Properties* in this Annual Information Form.

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)(1)	
	First Attributed	Cumulative at Year End
Prior thereto	4,609	4,609
2011	1,599	3,959
2012	2,218	2,490
2013	7,586	10,795

Note:

(1) The GLJ Report also attributes to Parex' assets for the year ended December 31, 2013, an immaterial amount of probable undeveloped natural gas reserves of 54 MMcf (first attributed) and 981 MMcf (cumulative at year-end). No probable undeveloped natural gas reserves were attributed for the years ended December 31, 2012 and 2011 or prior thereto.

The GLJ Report disclosed Company gross probable undeveloped reserves of 10,795 mbbl before royalties. Probable reserves are less certain to be recovered than proved reserves. The Company believes that it has or will have capital spending plans in place during 2014 and 2015 to drill the necessary locations to permit these probable reserves to be reclassified as proved. However, this reclassification will also depend in large part upon the performance of new and existing wells.

See *Principal Properties* and *Statement of Reserves Data and Other Information – Additional Information Relating to Reserves Data - Future Development Costs* for a description of the Company's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates.

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

At this time, the Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations. The Company does not anticipate any significant economic factors or significant uncertainties will affect any particular components of the Reserves Data. However, reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance, and subsequent drilling results, that are beyond the Company's control. See *Risk Factors*.

Future Development Costs

The following table sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) based upon the GLJ Report.

($000s)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
2014	100,225	118,800
2015	40,341	86,394
2016	3,823	24,293
2017	2,122	-
2018	-	-
Total for all years undiscounted	147,188	232,398
Total for all years discounted at 10% per year	135,425	208,919

Parex expects to use a combination of internally generated cash from operations, working capital and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the GLJ Report. There can be no guarantee that funds will be available or that the Board of Directors of the Company will allocate funding to develop all of the reserves attributable in the GLJ Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow. Further, the Company may choose to delay development depending upon a number of circumstances including the existence of higher priority expenditures and available cash flow.

Interest expense or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Company does not anticipate that interest or other funding costs would make further development of any of the Company's properties uneconomic.

Other Oil and Natural Gas Information

Unless otherwise stated, the following information is presented as at December 31, 2013. The Company does not believe that there have been any material changes to such information since such date.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which the Company held a working interest as at December 31, 2013. The Company did not have a working interest in any natural gas wells.

	Oil Wells				Other Wells(3)	
	Producing		Non-Producing			
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Colombia	64	46	8	6	13	9
Trinidad	-	-	1	1	1	1

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.
(3) Includes service, disposal, injection and standing wells.

Of the non-producing wells, 1 (0.3 net) oil wells were capable of production and had reserves assigned to them and 6 (5 net) oil wells were capable of production and had no reserves assigned to them. None of the non-producing oil wells were placed on production as of date of this Annual Information Form.

Properties with No Attributed Reserves

The following table sets out Parex and its Subsidiaries' developed and undeveloped land holdings as at December 31, 2013.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Colombia	3,024	2,051	2,012,330	1,464,584	2,015,354	1,466,635
Trinidad	40	32	218,881	2,409	218,921	2,441

All of Parex and its Subsidiaries' unproved properties are located in Trinidad & Tobago and Colombia. See *Principal Properties*. Within the next year, 69,915 gross (69,915 net) acres on the Colombian Block LLA-29 are scheduled to expire and Parex expects to receive either a contract extension or to fulfill the contractual obligation required to retain its rights to explore, develop and exploit the undeveloped property. Parex has fulfilled all work commitments on Block-LLA 30 and is in the process of applying to the ANH to enter the second phase. Development of the Company's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under *Risk Factors* herein. Parex does not expect its rights to explore, develop and exploit any of its undeveloped properties in Trinidad and Tobago to expire within the calendar year**.**

Forward Contracts

See Note 232, "*Financial Instruments and Financial Risk Management*" and Note 254, "*Commitments*", to the consolidated financial statements of the Company for the year ended December 31, 2013, which information is incorporated herein by reference and can be found on the Company's website at www.parexresources.com and on SEDAR at www.sedar.com. The nature of crude oil operations exposes the Company to risks associated with fluctuations in commodity prices and foreign currency exchange rates. Periodically, the Company may manage these risks through the use of derivative instruments. The Board of Directors of the Company periodically reviews the results of all risk management activities on all outstanding positions.

As part of its risk management program, Parex has entered into the following commodity price derivative contracts:

Term	**Commodity**	**Counterparty**	**bbl/d**	**Price /bbl**	**Option Type**
January 1 – March 31, 2014	Crude Oil	HSBC	1,000	$109.01	Fixed Price
January 1 – March 31, 2014	Crude Oil	HSBC	1,000	$100.00 - $111.25	Collar
January 1 – March 31, 2014	Crude Oil	Scotiabank	1,000	$105.00	Fixed Price
January 1 – March 31, 2014	Crude Oil	Scotiabank	1,000	$107.00	Fixed Price
January 1 – March 31, 2014	Crude Oil	Scotiabank	1,000	$103.00	Put
April 14 – September 30, 2014	Crude Oil	Scotiabank	1,000	$103.00	Put

As part of its risk management program, Parex has entered into the following foreign currency risk management contracts:

Term	**Reference**	**Counterparty**	**Type**	**Amount USD**	**Price(COP)**
November 12, 2013 to April 10, 2014	Colombian Peso	Scotiabank	Collar	$10 million	1,900 - 1,997
November 12, 2013 to June 10, 2014	Colombian Peso	Scotiabank	Collar	$10 million	1,900 - 2,022

Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates well abandonment and reclamation costs area by area. Such costs are included in the GLJ Report as deductions in arriving at future net revenue.

The following table sets forth abandonment and reclamation costs deducted in the estimation of the Company's future net revenue:

Forecast Prices and Costs ($000's)

Year	Total Proved Abandonment Costs	Total Proved plus Probable Abandonment Costs
2014	1,000	1,000
2015	1,339	969
2016	2,744	1,418
Thereafter	11,061	17,691
Total Undiscounted	16,144	20,144
Total Discounted @ 10%	10,748	11,193

The expected total abandonment and reclamation costs included in the GLJ Report for 50 net wells under the proved reserves category as at December 31, 2013 is $16,144,000 undiscounted ($10,748,000 discounted at 10%) based on forecast prices and costs.

Tax Horizon

The GLJ report forecasts cash taxes in Colombia to be incurred in 2014 and the Company incurred cash taxes in 2012 and 2013. The tax horizon for Parex Trinidad depends upon the level of success, if any, in finding and producing oil and natural gas in Trinidad.

Costs Incurred

The following table summarizes certain costs incurred by the Company for the year ended December 31, 2013:

	Property Acquisition Costs ($000's)			
Country	Proved Properties	Unproved Properties	Exploration Costs ($000's)	Development Costs ($000's)
Colombia	12,489	-	60,931	157,170
Trinidad	-	-	2,121	-
Total	12,489	-	63,052	157,170

Exploration and Development Activities

The following table sets forth the wells in which the Company participated during the year ended December 31, 2013. The Company did not participate in any wells in Trinidad & Tobago during the year ended December 31, 2013.

Colombia

	Exploratory		Appraisal		Development		Injection		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Oil	10	7	18	12	3	2	-	-	31	21
Gas	-	-	-	-	-	-	-	-	-	-
Service	1	1	3	2	-	-	-	-	4	3

	Exploratory		Appraisal		Development		Injection		Total	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Stratigraphic Test	-	-	-	-	-	-	-	-	-	-
Dry	3	2	-	-	-	-	-	-	3	2
Total	14	10	21	14	3	2	-	-	38	26

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.

See *Principal Properties* for a description of Parex and its Subsidiaries' current and proposed exploration and development activities.

Decommissioning Liabilities

The Company accounts for decommissioning liabilities in accordance with IFRS. This standard requires liability recognition for decommissioning liabilities associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the standard, the estimated fair value of each decommissioning liability is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Company's risk-free interest rate. The obligation is reviewed regularly by Management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold. Actual restoration expenditures are charged to the accumulated obligation as incurred. The related cost is recognized as an asset and is included in costs subject to depletion.

In the Company's audited and consolidated financial statements as at December 31, 2013, the estimated total inflated, undiscounted amount required to settle the asset retirement obligations in respect of the Company's producing and non-producing wells and facilities was approximately $19.4 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 20 years. The 5 percent discounted present value of this amount is approximately $13.8 million. The Company does not expect to incur the majority of these expenditures over the next three financial years.

Environmental Liabilities

Liabilities for environmental costs are recognized in the period in which they are incurred, normally when the asset is developed and the associated costs can be estimated. These liabilities are in addition to the decommissioning liabilities due to government regulations that require the Company to perform additional mitigation against the environmental issues attributed to water usage and deforestation from oil and gas activities performed. In addition, the timing of expected settlement of the environmental liabilities differs from the timing of expected settlement of the decommissioning liabilities. Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. In the Company's audited and consolidated financial statements as at December 31, 2013, the estimated total inflated, undiscounted amount required to settle the environmental obligations was approximately $8.4 million. These obligations are expected to be settled over the next 5 years. The 6 percent discounted present value of this amount is approximately $7.3 million. The Company expects to incur approximately $4.6 million of these expenditures over the next three financial years.

Production Estimates

The following table sets out the volumes of gross and net production estimated in the GLJ Report for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under *Statement of Reserves Data and Other Oil and Gas Information – GLJ Report*. The total production estimates disclosed in the following table include an immaterial amount of production related to natural gas reserves. The GLJ Report does not estimate any volumes of gross or net production related to heavy oil or NGLs.

	Light and Medium Oil (bbls/d)		Total (boe/d)	
	Gross	**Net**	**Gross**	**Net**
Proved Producing	12,555	10,457	12,699	10,590
Developed Non-Producing	411	378	411	378
Undeveloped	4,051	3,550	4,051	3,550
Total Proved	17,017	14,385	17,161	14,518
Total Probable	3,688	3,201	3,760	3,268
Total Proved Plus Probable	20,705	17,586	20,921	17,785
Total Possible	2,257	1,915	2,257	1,915
Total Proved Plus Probable Plus Possible	22,962	19,501	23,178	19,700

The following tables set out the volumes of gross and net production estimated in the GLJ Report for the year ended December 31, 2014 for the Company's fields that account for 20% or more of the Company's total gross and net production estimated in the GLJ Report for the year ended December 31, 2014:

Las Maracas, Colombia

	Light and Medium Oil (bbls/d)		Total (boe/d)	
	Gross	**Net**	**Gross**	**Net**
Proved Producing	3,858	2,885	3,858	2,885
Developed Non-Producing	-	-	-	-
Undeveloped	762	566	762	566
Total Proved	4,620	3,451	4,620	3,451
Total Probable	720	529	720	529
Total Proved Plus Probable	5,340	3,980	5,340	3,980
Total Possible	583	428	583	428
Total Proved Plus Probable Plus Possible	5,923	4,408	5,923	4,408

Production History

The following table sets forth certain information in respect of the gross Company production, product prices received, royalties paid, production costs and the netbacks received by the Company for each quarter of the last financial year.

	Quarter Ended 2013				Year Ended 2013
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**December**
Average Daily Production(1)					
Light and Medium Oil (Bbl/d)	17,287	16,199	15,463	14,440	15,854
Average Price Received (net of quality adjustment)					
Light and Medium Oil ($/Bbl)	101.64	106.41	99.34	109.63	104.20

	Quarter Ended 2013 Dec. 31	Sept. 30	June 30	Mar. 31	Year Ended 2013 December
Royalties Paid					
Light and Medium Oil ($/Bbl)	11.73	13.75	13.65	15.15	13.46
Operating and Transportation Expenses ($/BOE)					
Light and Medium Oil ($/Bbl)	29.13	28.78	27.47	27.45	28.04
Netback Received ($/BOE)(2)					
Light and Medium Oil ($/Bbl)	60.78	63.88	58.22	67.03	62.70

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.
(3) Parex Trinidad does not currently have and did not have any prior oil and natural gas production or oil and natural gas reserves in the year ended December 31, 2013.

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2013:

	Light and Medium Oil (Bbls/d)	BOE (BOE/d)
Las Maracas, Colombia	5,266	5,266
Kona, Colombia	4,532	4,532
Tua, Colombia	2,060	2,060
Total	11,858	11,858

Parex Trinidad does not currently have and did not have any prior oil and natural gas production or oil and natural gas reserves in the year ended December 31, 2013.

DIVIDEND POLICY

Parex has not paid any dividends on the outstanding Common Shares. The Board of Directors of Parex will determine the actual timing, payment and amount of dividends, if any, that may be paid by Parex from time to time based upon, among other things, the level of cash flow, results of operations and financial condition, the need for funds to finance ongoing operations and other business considerations as the Board of Directors of Parex considers relevant, including the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company consists of an unlimited number of Common Shares without nominal or par value. As at March 18, 2014, there were 109,427,024 Common Shares issued and outstanding. The following is a description of the rights, privileges, instructions and conditions attaching to the Common Shares.

The Company is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled: (i) to dividends if, as and when declared by the Board of Directors; (ii) to vote at any meetings of the holders of Common Shares; and (iii) upon liquidation, dissolution or winding up of the Company, to receive the remaining property and assets of the Company.

On September 29, 2009, the Board of Directors of Parex approved the adoption of a shareholder protection rights plan (the "**Parex Shareholder Rights Plan**"), which Parex Shareholder Rights Plan was approved by shareholders of PARI on October 30, 2009 and May 23, 2012. Pursuant to the Parex Shareholder Rights Plan, one right ("**Right**") is attached to each Common Share. The Rights will separate from the Common Shares to which they are attached and will become exercisable upon the occurrence of certain events in accordance with the Parex Shareholder Rights Plan. Subject to adjustment as provided in the Parex Shareholder Rights Plan, each Right will entitle the holder to purchase one Common Share at a price equal to $50.00 (the "**Exercise Price**") and, in the event of a "Flip-In Event", as that term is defined in the Parex Shareholder Rights Plan, each Right will constitute the right to purchase from the Company, upon payment of the Exercise Price and otherwise exercising such Right in accordance with the terms of the Parex Shareholder Rights Plan, that number of Common Shares having an aggregate Market Price (as defined in the Parex Shareholder Rights Plan), on the date of consummation or occurrence of such Flip-In Event equal to four times the Exercise Price for an amount in cash equal to the Exercise Price. The Parex Shareholder Rights Plan is similar to plans adopted recently by several other Canadian issuers and approved by their securityholders. A copy of the Parex Shareholder Rights Plan is available on the Company's SEDAR profile at www.sedar.com.

DESCRIPTION OF DEBENTURES

The Debentures were issued under the Indenture between the Company and the Debenture Trustee. The following description of the Debentures is a summary of their material attributes and characteristics and is subject to the detailed provisions of the Indenture and is qualified in its entirety by reference to the Indenture. The following summary uses words and terms which are defined in the Indenture. For full particulars, reference is made to the Indenture, which is available for inspection at the offices of the Company or on SEDAR at www.sedar.com. Particular provisions of the Indenture, which are referred to in this Annual Information Form, are qualified in their entirety by the reference to the Indenture.

General

The Debentures are limited to an aggregate principal amount of Cdn$85 million. The Company may, however, from time to time, without the consent of the holders of any outstanding Debentures, issue debentures in addition to the Debentures. The Debentures are issuable only in denominations of Cdn$1,000 and integral multiples thereof. The Debentures have a maturity date of June 30, 2016.

Unless an Event of Default has occurred and is continuing, the Company may elect, from time to time, subject to applicable regulatory approval, to satisfy its obligation to pay the Interest Obligation on an Interest Payment Date: (i) in cash; (ii) by delivering sufficient Common Shares to the Debenture Trustee for sale to satisfy the Interest Obligation on the Interest Payment Date, in which event holders of the Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares; or (iii) any combination of (i) and (ii) above. See — *Interest Payment Election* below.

The Debentures bear interest at 5.25 percent per annum, which is payable semi-annually on June 30 and December 31 in each year, computed on the basis of a 365-day year. Interest on the Debentures is payable in lawful money of Canada as specified in the Indenture.

Principal on the Debentures is payable in lawful money of Canada or, at the Company's option and subject to applicable regulatory approval and provided no Event of Default has occurred and is continuing, by delivery of Common Shares to satisfy, in whole or in part, the Company's obligation to repay the principal under the Debentures, as further described under **–** *Payment upon Redemption or Maturity* and **–** *Redemption and Purchase*.

The Debentures are direct obligations of the Company and are not be secured by any mortgage, pledge, hypothec or other charge and are subordinated to Senior Indebtedness. The Indenture does not restrict the Company or its Subsidiaries from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

The Debentures are transferable, and may be presented for conversion, at the principal offices of the Debenture Trustee in Calgary, Alberta.

Conversion Privilege

Each Debenture is convertible at the option of the holder thereof into fully paid and non-assessable Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earliest of: (i) the Maturity Date; (ii) the last Business Day immediately preceding the Redemption Date (as defined herein); and (iii) the last Business Day immediately preceding the Change of Control Purchase Date, in each case, at the Conversion Price, representing a conversion rate of approximately 98.5222 Common Shares per Cdn$1,000 principal amount of Debentures, subject to adjustment in accordance with the Indenture. Upon conversion of any Debentures, the holder thereof will be eligible to receive accrued and unpaid interest thereon in cash up to, but excluding, the date of conversion.

Holders converting their Debentures will become holders of record of Common Shares on the date of conversion provided that, if a Debenture is surrendered for conversion on a day on which the register of Common Shares is closed, the person entitled to receive Common Shares shall become the holder of record of such Common Shares as at the date on which such register is next reopened. Notwithstanding the foregoing, no Debentures may be converted on an Interest Payment date or during the five business days preceding June 30 and December 31 in each year, commencing December 31, 2011, as the registers of the Debenture Trustee will be closed during such periods.

Subject to the provisions thereof, the Indenture provides for the adjustment of the Conversion Price in certain events including: (i) the subdivision or consolidation of the outstanding Common Shares; (ii) the issuance of Common Shares or securities convertible into Common Shares by way of stock dividend or otherwise; (iii) the issuance of options, rights or warrants to all or substantially all the holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95 percent of the then Current Market Price (as defined hereafter) of the Common Shares; (iv) the distribution to all holders of Common Shares of any securities or assets; (v) the payment to all holders of Common Shares in respect of an issuer bid for Common Shares by the Company to the extent that the market value of the payment exceeds the then market price of the Common Shares on the date of expiry of the bid; and (vi) the payment of cash dividends to holders of Common Shares.

Provided the Common Shares are then listed on the TSX (or such other recognized stock exchange), the term "**Current Market Price**" is defined in the Indenture to mean, on any day, the volume weighted average trading price of the Common Shares on the TSX (or such other recognized stock exchange) for the 20 consecutive trading days ending on the fifth trading day preceding such date.

Subject to prior regulatory approval, if required, there will be no adjustment of the Conversion Price in respect of any event described in (ii), (iii) or (iv) above if, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to the applicable record date or effective date. The Company will not be required to make adjustments in the Conversion Price unless the cumulative effect of such adjustments would change the Conversion Price by at least 1 percent. However, any adjustments that are less than 1 percent of the Conversion Price will be carried forward and taken into account when determining subsequent adjustments.

In the case of: (i) any reclassification, capital reorganization or change (other than a change resulting only from consolidation or subdivision) of the Common Shares; (ii) the Company's amalgamation, arrangement, consolidation or merger with or into any other entity; (iii) any sale, transfer or other disposition of the Company's properties and assets as, or substantially as, an entirety to any other entity; or (iv) the Company's liquidation, dissolution or winding-up, the terms of the conversion privilege will be adjusted so that each Debenture will, after such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up, be exercisable for the kind and amount of the Company's securities or property, or of such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, capital reorganization, change, amalgamation, arrangement, consolidation, merger, sale, transfer, disposition, liquidation, dissolution or winding-up if on the effective date thereof it had been the holder of the number of Common Shares into which the Debenture was convertible prior to the effective date thereof.

No fractional Common Shares will be issued upon conversion of the Debentures. In lieu thereof, the Company will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share. Upon conversion, the Company may offer, and the converting holder may agree to the delivery of, cash for all or a portion of the Debentures surrendered in lieu of Common Shares.

Redemption and Purchase

The Debentures will not be redeemed by the Company before July 1, 2014 (except in certain limited circumstances following a Change of Control). See – *Repurchase upon a Change of Control* below. On or after July 1, 2014 and prior the Maturity Date, the Debentures may be redeemed by the Company in whole or in part from time to time at the Company's option on not more than 60 days' and not less than 40 days' prior written notice at a redemption price equal to the principal amount plus accrued and unpaid interest thereon, if any, up to but excluding the Redemption Date, provided that the Current Market Price of the Common Shares on the date on which notice of redemption is given is not less than 125 percent of the Conversion Price.

In the case of redemption of less than all of the Debentures, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX (or such other recognized exchange on which the Common Shares may be listed).

The Company will have the right to purchase Debentures for cancellation in the market, by tender or by private contract, at any time, subject to regulatory requirements.

Payment upon Redemption or Maturity

On any Redemption Date or on the Initial Maturity Date or Maturity Date, as applicable, the Company will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding Debentures, together with accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption. On any Redemption Date or on the Maturity Date, as applicable, the Company may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, provided that no Event of Default has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Debentures. Payment for such Debentures subject to the election would be satisfied by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures subject to the election which are to be redeemed or have matured by 95 percent of the Current Market Price of the Common Shares on the Redemption Date or Maturity Date, as applicable. In the event a holder of Debentures exercises its conversion rights following delivery of a notice of redemption by the Company, such holder shall be entitled to receive the applicable number of Common Shares to be received on conversion on the Business Day immediately preceding the Redemption Date, plus any accrued and unpaid interest for the period from the latest Interest Payment Date to but excluding date of conversion. Any accrued and unpaid interest will be paid in cash. The Company will not be entitled to issue Common Shares to satisfy its payment obligations on the Initial Maturity Date.

No fractional Common Shares will be issued upon redemption or maturity of the Debentures; in lieu thereof, the Company will satisfy such fractional interest by a cash payment equal to the relevant fraction of the Current Market Price of a whole Common Share.

Cancellation

All Debentures converted, redeemed or purchased will be cancelled and may not be reissued or resold.

Rank

The Debentures are direct, unsecured obligations of the Company and will be fully subordinated to all Senior Indebtedness. The Debentures rank equally with one another and, other than Senior Indebtedness, with all other existing and future unsecured indebtedness of the Company and rank *pari passu* with all other existing and future unsecured subordinated indebtedness of the Company to the extent subordinated on the same terms, and have priority over the payment of any declared but unpaid dividends on the Common Shares. The Indenture does not restrict the ability of the Company or its Subsidiaries from incurring additional indebtedness, including Senior Indebtedness, or from mortgaging, pledging or charging their respective properties to secure any indebtedness or liabilities, including Senior Indebtedness.

Subordination

The payment of the principal and premium, if any, of, and interest on, the Debentures is subordinated and postponed, and subject in right of payment in the circumstances referred to below and more particularly as set forth in the Indenture, to the full and final payment of all Senior Indebtedness of the Company. "**Senior Indebtedness**" of the Company is defined in the Indenture and includes all obligations, liabilities and indebtedness of the Company and its Subsidiaries which would, in accordance with Canadian generally accepted accounting principles, be classified upon a consolidated balance sheet of the Company as liabilities of the Company or its Subsidiaries and, whether or not so classified, shall include (without duplication): (a) indebtedness of the Company or its Subsidiaries for borrowed money; (b) obligations of the Company or its Subsidiaries evidenced by bonds, debentures, notes or other similar instruments; (c) obligations of the Company or its Subsidiaries arising pursuant or in relation to bankers' acceptances, letters of credit, letters of guarantee, performance bonds and surety bonds (including payment and reimbursement obligations in respect thereof) or indemnities issued in connection therewith; (d) obligations of the Company or its Subsidiaries under any swap, hedging or other similar contracts or arrangements; (e) obligations of the Company or its Subsidiaries under guarantees, indemnities, assurances, legally binding comfort letters or other contingent obligations relating to Senior Indebtedness or other obligations of any other person which would otherwise constitute Senior Indebtedness within the meaning of this definition; (f) all indebtedness of the Company or its Subsidiaries representing the deferred purchase price of any property including, without limitation, purchase money mortgages; (g) accounts payable to trade creditors; (h) all renewals, extensions and refinancing of any of the foregoing; and (i) all costs and expenses incurred by or on behalf of the holder of any Senior Indebtedness in enforcing payment or collection of any such Senior Indebtedness, including enforcing any security interest securing the same. "Senior Indebtedness" shall not include any indebtedness that would otherwise be Senior Indebtedness if it is expressly stated to be subordinate to or rank *pari passu* with the Debentures;

The Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to the Company, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of the Company, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Company, then holders of Senior Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Indenture also provides that the Company will not make any payment, and the holders of the Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures: (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; or (b) at any time when a default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of Senior Indebtedness and the notice of such default, event of default or acceleration has been given by or on behalf of holders of Senior Indebtedness to the Company, unless the Senior Indebtedness has been repaid in full.

The Debenture Trustee and the Company are also authorized (and obligated upon a request from the Company) under the Indenture to enter into subordination agreements on behalf of the holders of Debentures with any holder of Senior Indebtedness.

Repurchase upon a Change of Control

Within 30 days following the occurrence of a Change of Control, the Company will be required to make a cash offer to purchase all of the Debentures (the "**Debenture Offer**") at a price equal to 100 percent of the principal amount thereof plus accrued and unpaid interest thereon (the "**Offer Price**"). A Change of Control shall include: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids* and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 – *Take-Over Bids and Issuer Bids*) of ownership of, or voting control or direction over, 50 percent or more of the issued and outstanding Common Shares; or (ii) the sale or other transfer of all or substantially all of the Company's consolidated assets, excluding a sale, merger, reorganization or other similar transaction if the previous holders of the Common Shares hold at least 50 percent of the voting control in such merged, reorganized or other continuing entity (each a "**Change of Control**").

The Indenture contains notification and repurchase provisions requiring the Company to give written notice to the Debenture Trustee of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. The Debenture Trustee will thereafter promptly mail to each holder of Debentures a notice of the Change of Control together with a copy of the Debenture Offer to repurchase all outstanding Debentures.

If Debentures representing 90 percent or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control are tendered for purchase following a Change of Control (other than Debentures held at the date of the take-over bid by or on behalf of the offeror, associates or affiliates of the offeror or any one acting jointly or in concert with the offeror), the Company will have the right to redeem all remaining Debentures in cash on the purchase date at the Offer Price. Notice of such redemption must be given to the Debenture Trustee by the Company within ten days following expiry of the right of the holders of the Debentures to require repurchase after the Change of Control and, as soon as possible thereafter, by the Debenture Trustee to the holders of Debentures not tendered for purchase.

The Company will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of Debentures in the event of a Change of Control.

Cash Change of Control

In addition to the requirement for the Company to make a Debenture Offer in the event of a Change of Control, if a Change of Control occurs on or before the Maturity Date in which 10 percent or more of the consideration for the Common Shares in the transaction or transactions constituting a Change of Control consists of: (i) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenters' appraisal rights); (ii) equity securities that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (iii) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then subject to regulatory approvals, during the period beginning ten trading days before the anticipated date on which the Change of Control becomes effective and ending 30 days after the Debenture Offer is delivered, holders of Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, subject to and upon completion of the Change of Control, in addition to the number of Common Shares they would otherwise be entitled to receive as set out under – *Conversion Privilege* above, an additional number of Common Shares per Cdn$1,000 principal amount of Debentures as set out in the Indenture (in each case, a "**Make-Whole Premium**").

The number of additional Common Shares per Cdn$1,000 principal amount of Debentures constituting the relevant Make-Whole Premium will be determined by reference to the table included in the Indenture and is based on the date on which the Change of Control becomes effective (the "**Effective Date**") and the price (the "**Offer Price**") paid per Common Share in the transaction constituting the Change of Control. If holders of Common Shares receive (or are entitled and able in all circumstances to receive), only cash in the transaction, the Offer Price will be the cash amount paid per Common Share. Otherwise, the Offer Price will be equal to the Current Market Price of the Common Shares immediately preceding the Effective Date of such transaction.

Interest Payment Election

Unless an Event of Default has occurred and is continuing, the Company may elect, from time to time, subject to applicable regulatory approval, to satisfy its obligation to pay the Interest Obligation on an Interest Payment Date: (i) in cash; (ii) by delivering sufficient Common Shares to the Debenture Trustee for sale, to satisfy the Interest Obligation on the Interest Payment Date, in which event holders of the Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares; or (iii) any combination of (i) and (ii) above.

The Indenture provides that, upon the Company making a Common Share Interest Payment Election, the Debenture Trustee will: (i) accept delivery from the Company of Common Shares; (ii) accept bids with respect to, and consummate sales of, such Common Shares, each as the Company shall direct in its absolute discretion through investment banks, brokers or dealers identified by the Company; (iii) invest the proceeds of such sales in securities issued or guaranteed by the Government of Canada which mature prior to the applicable Interest Payment Date, and use the proceeds received from investment in such permitted government securities, together with any additional cash provided by the Company, to satisfy the Interest Obligation; and (iv) perform any other action necessarily incidental thereto.

The Indenture sets out the procedures to be followed by the Company and the Debenture Trustee in order to effect the Common Share Interest Payment Election. If a Common Share Interest Payment Election is made, the sole right of a holder of Debentures in respect of interest will be to receive a cash payment equal to the interest owed on his Debentures from the Debenture Trustee out of the proceeds of the sale of Common Shares (plus any amount received by the Debenture Trustee from the Company) in full satisfaction of the Interest Obligation, and the holder of such Debentures will have no further recourse to the Company in respect of the Interest Obligation.

Notwithstanding the foregoing, neither the Company making the Common Share Interest Payment Election nor the consummation of sales of Common Shares will: (i) result in the holders of the Debentures not being entitled to receive, on the applicable Interest Payment Date, cash in an aggregate amount equal to the interest payable on such Interest Payment Date; or (ii) entitle or require such holders to receive any Common Shares in satisfaction of the Interest Obligation. The Common Share Interest Payment Election will not be available for interest payable on or prior to the Initial Maturity Date.

Events of Default

The Indenture provides that an event of default (an "**Event of Default**") in respect of the Debentures will occur if certain events described in the Indenture occur, including if any one or more of the following described events has occurred and continuing with respect to the Debentures: (i) failure for 30 days to pay interest on the Debentures when due; (ii) failure to pay principal or premium, if any (whether by payment in cash or delivery of Common Shares), on the Debentures when due, whether at maturity, upon redemption, on a Change of Control, by declaration or otherwise; (iii) default in the delivery, when due, of any Common Shares or other consideration, including any Make-Whole Premium, payable upon conversion with respect to the Debentures, which default continues for 15 days; (iv) default in the observance or performance of any covenant or condition of the Indenture and the failure to cure (or obtain a waiver for) such default for a period of 30 days after notice in writing has been given by the Debenture Trustee or from holders of not less than 25 percent of the aggregate principal amount of the Debentures specifying such default and requiring the Company to rectify or obtain a waiver for same; and (v) certain events of bankruptcy, insolvency or reorganization of the Company under bankruptcy or insolvency laws.

If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and will, upon the request of holders of not less than 25 percent in principal amount of the then outstanding Debentures (declare the principal of (and premium, if any) and interest on all outstanding Debentures to be immediately due and payable.

Governing Laws

The Indenture and Debentures are governed by, and construed in accordance with, the laws of the Province of Alberta and the federal laws of Canada applicable therein.

Forward Contracts – Debenture

Associated with the Debentures, on December 30, 2012, the Company entered into a Cross Currency Interest Rate Swap ("**CCIRS**") with two financial institutions who are members of the Company's credit facility. Under the terms of the CCIRS, a US dollar amount of the Debenture was fixed for purposes of interest and principal repayment at a notional amount of $85.7 million. Also, the fixed coupon rate of Cdn 5.25% was swapped for a fixed coupon rate at US 4.45%.

BANK DEBT

On May 23, 2012, Parex entered into a $200 million senior secured credit facility with a syndicate of banks led by a major Canadian bank with a borrowing base of $50 million. The credit facility borrowing base was increased in 2013, and as at March 17, 2014 the facility consists of a reserve-based revolving facility with a borrowing base of $100 million including an operating line of $10 million. The revolving facility has a two year term, and may be extended by Parex for an additional 365 days after attaining syndicate approval. The facility is subject to re-determination of the borrowing base semi-annually on November 30 and May 31 of each year, beginning on November 30, 2012. The borrowing base is determined based on, among other things, the Company's reserve report, results of operations, the lenders view of the current and forecasted commodity prices and the current economic environment. Advances under the revolving facility bear interest at rates ranging from US base rate or LIBOR plus 2.75% - 3.50% per annum, depending on utilization. Advances on the operating line bear interest at rates ranging from Canadian prime plus 1.75% - 2.50% per annum, dependent on utilization. Undrawn amounts under the revolving facility bear a commitment fee ranging from 0.5% to 0.75% per annum, dependent on utilization.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Key covenants include a current ratio test of 1:1 adjusted for undrawn amounts on the credit facility plus fair value of inventoried oil, a rolling four quarter total funded debt to EBITDA test of 3.50:1, and other business operating covenants customary for a facility of this type. The authorized borrowing amount is subject to an interim review as discussed above. Security is provided for by a first fixed and floating charge debenture over all assets of Parex, a pledge of the shares of material subsidiaries and general assignment of book debts.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "PXT". The following sets forth the price range and volume of the Common Shares traded or quoted on the TSX (as reported by such exchange) for the periods indicated, in Canadian dollars.

	Price Range		
	High (Cdn$/share)	**Low (Cdn$/share)**	**Volume**
2014			
January	7.45	6.59	5,275,636
February	8.63	7.15	6,909,954
March (1 to 18)	9.37	8.56	5,944,756

	Price Range		
	High (Cdn$/share)	Low (Cdn$/share)	Volume
2013			
January	6.50	5.63	3,607,882
February	6.20	4.45	3,251,970
March	5.13	4.39	5,937,235
April	4.81	4.05	3,590,357
May	4.89	4.27	2,935,793
June	4.56	4.06	6,486,061
July	5.59	4.10	5,128,771
August	5.94	5.13	3,321,835
September	6.30	5.72	3,724,941
October	6.30	5.71	5,155,792
November	6.47	5.60	6,527,088
December	6.80	6.22	4,595,552

The Debentures are listed and posted for trading on the TSX under the symbol "PXT.DB". The following sets forth the price range and volume of the Debentures traded or quoted on the TSX (as reported by such exchange) for the periods indicated, in Canadian dollars.

	Price Range		
	High (Cdn$/Debenture)	Low (Cdn$/Debenture)	Volume
2014			
January	104.51	101.00	923,000
February	108.50	103.00	1,967,000
March (1 to 18)	112.00	108.00	1,745,000
2013			
January	103.03	100.35	880,000
February	103.00	99.00	152,000
March	101.49	99.50	656,000
April	100.54	95.40	858,000
May	99.50	97.76	1,857,000
June	99.70	96.18	742,000
July	101.00	96.50	1,754,000
August	100.99	99.52	830,000
September	101.50	99.87	1,022,000
October	101.50	99.25	364,000
November	101.50	100.01	975,000
December	103.34	101.99	1,904,000

PRIOR SALES

During the year ended December 31, 2013, the Company granted: (i) an aggregate of 4,270,575 stock options to acquire an aggregate of 4,270,575 Common Shares with a weighted average exercise price of Cdn$6.02; and (ii) an aggregate of 633,500 restricted share units to acquire an aggregate of 633,500 Common Shares.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

As at the date hereof, none of the Company's securities are subject to escrow or subject to contractual restrictions on transfer.

DIRECTORS AND OFFICERS

The names, provinces and countries of residence, positions held with the Company, and principal occupation of the directors and officers of the Company during the past five years are set out below, and, in the case of directors, the period each has served as a director of the Company. Each of the directors and officers listed below were previously directors or officers of PARI.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer[(4)]	Principal Occupation (for last 5 years)
Norman McIntyre[(3)(4)] Alberta, Canada	Director and Chairman since September 29, 2009	Independent Businessman since 2004. President of Petro-Canada from 2002 to 2004. Executive Vice President of Petro-Canada from 1995 to 2002. Member of the Institute of Corporate Directors having completed the Directors Education Program.
Curtis Bartlett[(1)(4)] Alberta, Canada	Director since September 29, 2009	Co-founder and Partner at Lorem Partners, a private equity investment firm. Over 20 years of experience as an entrepreneur and private equity investor. Director of several private companies.
John Bechtold[(2)(3)(4)] British Columbia, Canada	Director since September 29, 2009	Currently a Director of Parkland Fuel Corporation, an independent marketer of fuels across Canada, Mr. Bechtold brings over 40 years of broad oil, gas and energy related experience. He served at Petro-Canada from 1977 until retirement in a number of leadership roles. Following retirement he has also served on the Board of Directors of the British Columbia Oil & Gas Commission which regulates oil and natural gas activity in that province.
Robert Engbloom, Q.C.[(2)(3)(4)] Alberta, Canada	Director since September 29, 2009	Deputy Chair of Norton Rose Fulbright Canada LLP, a national law firm in Canada and a member of the global Norton Rose Fulbright Group. Mr. Engbloom has more than 30 years of experience in the areas of mergers and acquisitions, governance, corporate and securities law. His broad experience spans a range of businesses both public and private, operating nationally and internationally, primarily in the energy industry.
Wayne Foo[(4)] Alberta, Canada	President and Chief Executive Officer since September 29, 2009 and Director since August 28, 2009	Currently President and Chief Executive Officer of Parex. President and Chief Executive Officer of Dominion Energy Canada Ltd. from 1998 to October 2002, and then Consultant to March 2003. Director of Pengrowth Energy Corporation.
Barry Larson Alberta, Canada	Chief Operating Officer since September 29, 2009	Currently Chief Operating Officer of Parex. Director of Madalena Ventures. Vice President of Operations of Vermilion Oil and Gas (Trinidad) Ltd. from January 2003 to May 2004. Co-founder and Vice President of Aventura Energy Inc. from 1999 to 2003, a company that operated in Trinidad & Tobago and Argentina.
Ron Miller[(1)(4)] Alberta, Canada	Director since September 29, 2009	Co-founder and Partner of Lorem Partners, a private equity investment firm. Director of several private companies. Member of the Institute of Corporate Directors having completed the Directors Education Program.
W.A. (Alf) Peneycad[(2)(4)] Alberta, Canada	Director since September 29, 2009	Independent Businessman since 2006. Previously Vice President, General Counsel and Chief Compliance Officer for Petro-Canada from 2003 to 2006. Vice President, General Counsel and Corporate Secretary of Petro-Canada prior to 2003. Director for several other Canadian public companies including NiMin Energy Corp., Canadian Wireless Trust, and R Split III Corp. where he holds positions on the Audit and Finance, Corporate Governance and Human Resource Committees. Member of the Institute of Corporate Directors having completed the Directors Education Program.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer[(4)]	Principal Occupation (for last 5 years)
Kenneth Pinsky Alberta, Canada	Chief Financial Officer and Corporate Secretary since September 29, 2009	Currently Chief Financial Officer and Corporate Secretary of Parex. Previously, Chief Financial Officer of Ultima Energy Trust, a TSX listed Royalty Trust from 2001 to June 2004, and the Chief Financial Officer and director of a Canadian based private exploration and production company from September 2004 to January 2008.
David Taylor Alberta, Canada	Executive Vice President, Exploration & Business Developmentsince September 29, 2009	Currently Executive Vice President Exploration and Business Development of Parex. Prior thereto, Vice President, Exploration and International Operations with Husky Energy from August 2000 to July 2007 and Vice President, Exploration for Renaissance Energy from June 1998 to August 2000.
Paul Wright[(1)(4)] Alberta, Canada	Director since September 29, 2009	Currently works as a financial consultant and sits on the Board of Directors and is Chairman of the Audit Committee for Brickburn Funds Inc., a mutual fund company. He also sits on the Board of Directors of one non-profit organization. Mr. Wright is a Chartered Accountant with over 30 years of industry experience. He has worked in senior financial roles in both domestic and international oil and natural gas companies. Member of the Institute of Corporate Directors having completed the Directors Education Program.

Notes:

(1) Member of the Finance and Audit Committee.
(2) Member of the Corporate Governance, Compensation and Human Resources Committee.
(3) Member of the Operations and Reserves Committee.
(4) Parex' directors will hold office until the next annual general meeting of the Company's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at March 18, 2014, the directors and officers of Parex, as a group, beneficially owned or controlled or directed, directly or indirectly, 8,675,463 Common Shares or approximately 7.93 percent of the issued and outstanding Common Shares.

Cease Trade Orders

No current director or executive officer of the Company has, within the last ten years prior to the date of this Annual Information Form, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

Bankruptcies

No current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, 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 the assets of the director, officer or securityholder.

Penalties or Sanctions

No current director or officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) 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.

CONFLICTS OF INTEREST

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

FINANCE AND AUDIT COMMITTEE INFORMATION

Finance and Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Finance and Audit Committee of the Board of Directors is attached hereto as Schedule "C".

Composition of the Finance and Audit Committee

The members of the Finance and Audit Committee are Paul Wright, Ron Miller, and Curtis Bartlett. The members of the Finance and Audit Committee are independent (in accordance with National Instrument 52-110 – *Audit Committees*) and are financially literate. The following is a description of the education and experience of each member of the Finance and Audit Committee.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Paul Wright Calgary, Alberta (Chairman)	Yes	Yes	Currently works as a financial consultant and sits on the Board of Directors and is Chairman of the Audit Committee for Brickburn Funds Inc., a mutual fund company. He also sits on the Board of Directors of one non-profit organization. Mr. Wright is a Chartered Accountant with over 30 years of industry experience. He has worked in senior financial roles in both domestic and international oil and natural gas companies. Member of the Institute of Corporate Directors having completed the Directors Education Program.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Ron Miller Calgary, Alberta	Yes	Yes	Co-founder and Partner of Lorem Partners, a private equity investment firm. Director of several private companies. Until the completion of the Arrangement in November 2009, he acted as director and chair of the Audit Committee for PARI. Mr. Miller earned his Bachelor of Commerce degree from the University of Alberta in 1987, his Chartered Accountant designation while articling with KPMG in 1990, and his ICD.D designation in 2009.
Curtis Bartlett Calgary, Alberta	Yes	Yes	Co-founder and Partner at Lorem Partners, a private investment firm. Over 20 years of experience as an entrepreneur and private equity investor. Director of several private companies. Previously a director of PARI until the completion of the Arrangement in November 2009.

Pre Approval of Policies and Procedures

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

External Auditor Service Fees

Audit Fees

The Finance and Audit Committee has reviewed the nature and amount of non-audit services provided by PricewaterhouseCoopers LLP to the Company to ensure auditor independence. Fees paid to PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table. Payments made in foreign currencies have been translated to Canadian dollars at average exchange rates for each year.

Nature of Services	Fees Paid to Auditor in the Year Ended December 31, 2013 (Cdn$)	Fees Paid to Auditor in the Year Ended December 31, 2012 (Cdn$)
Audit Fees(1)	415,457	453,017
Audit-Related Fees(2)	-	21,525
Tax Fees(3)	164,121	90,702
All Other Fees(4)	96,869	175,945
Total	676,447	741,189

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's consolidated financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include the review and assistance with transition to IFRS.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit products and services.

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

The transfer agent and registrar for the Common Shares and Debentures is Valiant Trust Company. The Company's Common Shares are transferable at the offices of Valiant Trust Company in Calgary, Alberta and at the offices of BNY Trust Company of Canada in Toronto, Ontario.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Company and other than as disclosed below, as at December 31, 2013, there were no material legal proceedings to which the Company was a party or of which any of its respective properties was the subject matter of, nor were there any such proceedings known to the Company to be contemplated as at such date.

Parex, Parex Bermuda and Ramshorn have been named as defendants in the Lawsuit filed in the 61st Judicial District Court of Harris County, Texas along with other parties, including Nabors Industries Ltd. and a Bermuda-domiciled company, Nabors Global Holdings II Limited, by a Texas based private company (the "**Plaintiff**"). The Lawsuit relates to a share purchase agreement entered into by the Plaintiff and Nabors Global Holdings II Limited (the "**Seller**") (prior to the agreement entered into by Parex Bermuda and the Seller for the purchase of Ramshorn's class A shares) respecting the proposed purchase by the Plaintiff of the class A shares of Ramshorn, which prior agreement the Plaintiff claims was improperly terminated by the Seller. The Plaintiff is seeking specific performance remedies or, in the alternative, actual, consequential and exemplary damages. Each of Parex, Parex Bermuda and Ramshorn specially appeared in the Lawsuit to challenge the jurisdiction of the Texas Court and to seek dismissal of the claims against them.

A hearing on the jurisdictional aspects of the Lawsuit took place on November 19 and 20, 2012. The Texas Court found that it does not have jurisdiction over Parex Bermuda and ordered that all of the Plaintiff's claims and causes of action asserted against Parex Bermuda be dismissed for want of jurisdiction. The Texas Court overruled Parex and Ramshorn's jurisdictional challenges such that the Plaintiff's claims against Parex and Ramshorn were not dismissed. Parex and Ramshorn filed a Notice of Appeal of the Texas Court's rulings in respect of these jurisdictional matters, as well as the Plaintiff with respect to the Parex Bermuda ruling.

On January 28, 2014, the Texas Appeal Court reversed the decision of the Texas Court respecting Parex and dismissed all of the Plaintiffs' claims against Parex for lack of jurisdiction. The Texas Appeal Court also affirmed the decision of the Texas Court dismissing all of the Plaintiff's claims against Parex Bermuda for lack of jurisdiction. Lastly, the Texas Appeal Court affirmed the decision of the Texas Court respecting Ramshorn such that Ramshorn remains subject to the Lawsuit. The causes of action alleged against Ramshorn in the Lawsuit all relate to acts and conduct by Ramshorn that the Plaintiff alleges took place prior to Parex Bermuda's acquisition of Ramshorn. On February 12, 2014, the Plaintiff filed a combined motion requesting an initial reconsideration by the Texas Appeal Court of its decision regarding the Courts dismissal of Parex and Parex Bermuda as ruled on January 28, 2014. The Plaintiff's motion was entirely rejected by the Texas Appeal Court on March 6, 2014. On March 7, 2014 the Plaintiff filed a Statement of Claim at the Court of Queen's Bench of Alberta naming Parex, Parex Bermuda and RBC Dominion Securities, Inc. as defendants and setting forth causes of action and remedies substantially the same as have been alleged in the Lawsuit. This Statement of Claim has not been served on Parex or Parex Bermuda and unless and until such service occurs the Plaintiff may not pursue the action against either Parex or Parex Bermuda nor are Parex or Parex Bermuda obligated to take any steps in connection therewith.

During the year ended December 31, 2013, there were: (i) no penalties or sanctions against the Company imposed by a court relating to securities legislation or by a securities regulatory authority; (ii) no 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 (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Company, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10 percent of the outstanding voting securities of the Company, or any other Informed Person (as defined in NI 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Company or any of its subsidiaries.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, including purchase and sale agreements, the Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect other than the following:

1. The Parex Shareholder Rights Plan. See *Description of Capital Structure*.

2. A General Security Agreement in favour of EDC in respect of the Letters of Credit provided to the ANH that guarantees the exploration commitments for the Colombian exploration blocks. See *Description of the Business and Operations*.

3. The Indenture. See *Description of Debentures*.

4. The senior secured bank credit facility. See *Bank Debt.*

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 Parex other than GLJ, Parex' independent reserves evaluators, and PricewaterhouseCoopers LLP, Chartered Accountants, Parex' auditors. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of Parex or of Parex' 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 is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

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

INDUSTRY CONDITIONS

The following is a brief summary of the economic and energy market conditions encountered in conducting oil and natural gas operations in Colombia and Trinidad & Tobago. The industry related information in this section has been taken from public sources.

Colombia

Economic

According to the Economic Intelligence Unit Country Forecast (March 2014), GDP growth in Colombia was 4.7 percent in 2013 and expected to be 4.3 percent in 2014. Colombian inflation is expected to average between 2-4 percent in 2014-2018, within the central bank’s target range. The Colombian peso is expected to average Ps1, 1,943:$1 in 2014, compared with Ps1, 1869:$1 in 2013. The three year credit default swap ("**CDS**") rate, which provides an indication of counter-party credit risk, is currently approximately 78 basis points for the Government of Colombia.

Royalties

In 2004, the ANH released new fiscal terms based on a royalty/tax system, abolishing the incumbent association contract model. The most fundamental change to the terms is that Ecopetrol, the national oil company, has no mandatory back-in right. The contractor has rights to all production net of royalty.

Royalty payments vary depending on the quality of oil and the rate of production and are applied on a production area or, in some cases, block basis. For light/medium oil, the stated royalty rate is as presented in the following table:

Field Production (bbl/d)	Royalty Rate*
0-5,000	8%
5,001-125,000	8%-20%
125,001-400,000	20%
400,001-600,000	20%-25%

*For new discoveries of heavy oil, classified as those with an API equal to or less than 15º, the royalties will be 75% of the royalty rates for light and medium oils presented above.

All of Parex' Colombian contracts are subject to this sliding scale royalty.

High Price Participation

For contracts signed under the new ANH oil regulatory regime, in 2004 and onwards, a high price share of production applies once a production area has cumulatively produced more than 5 mmbbls of oil, determined before the deduction of royalties. For the Company's ANH contracts, the share of production to be paid is based on the established percent (S) of the part of the average monthly reference WTI price (P) that exceeds a base price (Po), divided by the average monthly reference price (P).

Quality	Base Price (Po) 2014 Threshold Prices
Less than 10º API	Nil
10º to 15º API	$54.20/bbl
15º to 22º API	$37.95/bbl
22º to 29º API	$36.59/bbl
Greater than 29º API	$35.22/bbl

Average Monthly Reference WTI Price (P)	Established Percentage (S)
$Po \leq P \leq 2Po$	30%
$2Po \leq P \leq 3Po$	35%
$3Po \leq P \leq 4Po$	40%
$4Po \leq P \leq 5Po$	45%
$5Po \leq P$	50%

Crude oil production with a quality above 29º API and a WTI oil price of $95/bbl results in a production share equivalent to an incremental 22 percent royalty, bringing the total government royalty to approximately 29 percent for a production area with production less than 10,000 bbl/d, excluding potential X-Factor. Threshold prices are adjusted annually and high price share is calculated after base royalties and X-Factor if applicable.

Parex has no outstanding material disputes in respect of the interpretation of the royalty regime and the High Price Participation. However, Parex is aware of disputes between ANH contract holders and the ANH regarding the High Price Participation royalty.

X-Factor

For certain Exploration Contracts acquired in the 2008 Heavy Oil Bid round and in subsequent bid rounds, the ANH required an additional royalty percentage, or X-Factor, to be paid by the Contractor to the ANH. The X-Factor is also now one of the bid criteria for new Exploration Contracts, and the minimum X-Factor is one percent.

Summary of Fiscal Terms by ANH Exploration Contract

Each Exploration Contract with the ANH has a sliding scale royalty of 8% - 25% based on the average monthly production level of a field, plus potentially two additional payments that vary by contract, a high price participation payment and an X-factor. The following table summarizes the high price participation factors and X-factors applicable to Parex' Exploration Contracts.

Block	X-Factor	High Price Participation Basis
LLA-16	1%	Exploitation area + sliding scale factor
LLA-20	1%	Exploitation area + sliding scale factor
LLA-24	1%	Exploitation area + sliding scale factor
LLA-26	1%	Exploitation area + sliding scale factor
LLA-29	1%	Exploitation area + sliding scale factor
LLA-30	1%	Exploitation area + sliding scale factor
LLA-57	1%	Block +sliding scale factor
Cabrestero	0%	Exploitation area + sliding scale factor
Cebucan	1%	Exploitation area + sliding scale factor
El Eden	0%	Exploitation area + sliding scale factor
Los Ocarros	0%	Exploitation area + sliding scale factor
LLA-17	1%	Exploitation area + sliding scale factor
LLA-32	1%	Exploitation area + sliding scale factor
LLA-34	1%	Exploitation area + sliding scale factor
LLA-40	1%	Block + sliding scale factor
Morpho(1)	6.5% GOR + 4% NPI	Sliding scale factor
Guariquies	0%	Exploitation area + sliding scale factor
VMM-11	1%	Exploitation area + sliding scale factor

Note:

(1) Associated with the Morpho Block, there is a 6.5% gross overriding royalty due to Ecopetrol and 4% net profit interest due to Platino. The net profit interest is calculated based on net profit.

Income Tax

The Company's Colombian branches are subject to a 34% tax on net income or a presumptive minimum tax of 3 percent of net equity, whichever is the greater. After January 1, 2016, the tax on net income will be reduced to 33%. Income tax losses can be carried forward indefinitely but can only be applied on a branch by branch basis. Unsuccessful exploration costs can be written off in the current year or in any of the following two years. Other exploration and development costs are amortized using units-of-production method. General administrative costs can be expensed, with only those relating to the Colombian entities being deductable.

Regulatory Regime

The regulatory regime in Colombia underwent a significant change, effective January 1, 2004, with the formation of the ANH, which has assumed the role of regulating the Colombian oil industry. This function was previously performed by Ecopetrol.

The ANH developed a new exploration risk contract that took effect near the end of the first quarter of 2005. This contract has significantly changed the way the industry views Colombia and has significantly increased the amount of new exploration in the country. In place of the earlier association contracts in which the government, through the state company (Ecopetrol) had an immediate back-in to production, the new agreement provides full risk/reward benefits for the contractor. Under the terms of the contract, the successful operator will retain the rights to all reserves, production and income from any new exploration block, subject to existing royalty and income tax regulations with a windfall surcharge provision for larger fields.

Previously, the ANH dealt with exploration acreage proposals on a "first-come, first-served" basis, but since 2008 has adopted a system of competitive bidding rounds, or rounds whereby the ANH invites a selected group of companies to submit proposals. Once the ANH is satisfied that the successful oil company has the proper technical and financial resources to fulfill its obligations under the proposed contract, a definitive work program is negotiated. This work program typically includes technical studies, reprocessing or shooting new seismic and/or drilling wells. The ANH contract term consists of three phases: (i) the exploration phase, which lasts six years and comprises an initial phase 1 lasting 3 years and an optional phase 2, which is also 3 years. The exploration phase can be extended for up to an additional four years under certain circumstances; (ii) upon a declared discovery, and at the contractor's request, the evaluation phase commences and lasts one to two years with up to a two year extension possible, during which the contractor must declare commerciality or relinquish the block; and (iii) the production phase with a basic 24 year term, extendable under certain circumstances. The duration of the exploration period is six years; however, the contractor may request an extension for up to four additional years provided that it presents an additional exploration program and relinquishes 50 percent of the area. Depending on the period requested, this period is also divided into phases as the contractor proposes. All discoveries must be reported to the ANH, while the Colombian Ministry of Mines and Energy defines the extent of the discovery.

If a discovery is made, the contractor has the option to request an appraisal period of up to two years, depending on the size and scope of the evaluation plan proposed. If, in the opinion of the ANH, there is sufficient reason, this period may also be extended. If the evaluation plan relates to a natural gas or heavy oil field, two additional years may be granted because of the complex planning and marketing required. At the end of this phase, the contractor must declare commerciality or return the block.

Once the evaluation phase is complete and the operator declares commerciality, the exploitation phase begins. The duration of the exploitation period of each declared field is 24 years. The contractor may obtain an extension of the exploitation period beyond the 24 years, if the contractor complies with three basic requirements: continuous production, an active enhanced oil recovery plan or infill project, and a payment of 5 percent for natural gas bold 10 percent for oil of the remaining reserves value.

Relinquishment of part or all the licence area depends on the phase in which operations are. Under normal circumstances the contractor must relinquish 50 percent of the area at the end of the six-year exploration period if the contractor continues to explore, and there is an evaluation program or a discovery. If not, the operator must relinquish 100 percent. Another 25 percent must be relinquished after the two-year evaluation phase expires. The operator and the ANH may also agree on the relinquishment of certain parts of a licence area during the initial six-year exploration period as part of the contract and on a block by block basis, depending on the scope of the exploration work program and the size of the area. The contractor also has the option to relinquish all or part of the area after each exploration phase.

Environmental Regulation

The environmental regulatory framework in Colombia which governs the oil and natural gas industry is divided into two parts: planning and compliance.

Planning

The Colombian Ministry of Environment, Housing and Territorial Development (the "**MADVT**") requires that environmental impact assessments ("**EIAs**") and environmental management plans ("**EMPs**") be submitted as the principal planning tools for all new projects, ensuring local and specific environmental and social variables are included in project planning. Following approval of the EIA, the MADVT awards an environmental licence. When a discovery is made, the environmental licence typically allows for a maximum one year of production testing, while the company prepares a new EIA and EMP for the development of a permanent oil and natural gas production field and development drilling.

Field pipeline design and construction is subject to a two part environmental licensing process. First, an environmental option assessment ("**EOA**") is conducted, whereby both the company and the government environmental authority review options to agree on an environmentally friendly pipeline design and layout. Once an agreement is reached, the company can apply for the pipeline environmental licence through a comprehensive EIA and EMP.

Once a production field's environmental licence is in place, development drilling, flowlines, batteries and other production infrastructure can be added by preparing specific EMPs.

Compliance

In Colombia, regulations relating to compliance standards include specific standards for water and air quality, wastewater and solid waste treatment and disposal, air emission control, and industrial hygiene. In addition, the environmental licence normally includes obligations which have to be compiled with by the operator.

Market Conditions

Colombia has a well-developed oil infrastructure system, comprising over 6,000 kilometres of crude and product pipelines. The system is concentrated on transporting crude from the main producing basins (Llanos and the Magdalenas), via a central hub at Vasconia in the interior, to Colombia's main oil export terminal at Coveñas on the Caribbean coast. Additionally, a key line runs separately from the Caño Limón field near the Venezuelan border to Coveñas. In the far south, the Oleoducto Trans-Andino carries crude to the Pacific port of Tumaco. At present, Phase 1 of the Bicentenario Pipeline is expected to begin transporting 120,000 bbls/d of crude oil from the Llanos Basin (Araguaney) to Banadia. Future phases would increase the capacity to 330,000 bbls per day of crude oil and terminate the pipeline at the port of Coveñas.

Colombia currently operates five refineries, all of which are owned by Ecopetrol. Two of these, Barrancabermeja and Cartagena, are main fuels refineries, accounting for almost all of the country's refining capacity. The remaining three refineries are small and simple. Total crude processing capacity is approximately 330,000 bbls/d. Current expansion plans are to increase processing capacity to approximately 415,000 bbls/d by 2017 with increased capabilities to process heavy and sour crude oil blends.

Trinidad & Tobago

Economic

Real GDP growth in Trinidad & Tobago was 1.2 percent in 2013. Inflation was 5.6 percent in 2013. The exchange rate of Trinidad & Tobago dollars to U.S. dollars is quasi-fixed and expected to remain relatively flat in 2014 at approximately 6.3 to 1. The Economic Intelligence Unit country risk for the Government of Trinidad & Tobago is BBB.

Royalties, Petroleum Production Levy, Supplemental Petroleum Tax and Green Fund Levy

Royalties on state lands vary between onshore and offshore licences, and between oil and natural gas. The standard oil/condensate rate is 12.5 percent. The onshore lease operatorships and farm-outs must often pay an over-riding royalty to the state which can add up to a further 35 percent. Royalties on freehold lands are subject to negotiation, but tend to be consistent with the state royalty rate.

Producers must also pay a Petroleum Production Levy ("**PPL**") and Supplemental Petroleum Tax ("**SPT**"). The PPL is up to 4 percent of gross income from crude oil for producers of more than 3,500 barrels of oil per day. SPT is charged on production of oil based on an oil price-sensitive rate. The rate is 18 percent for oil prices in the range of WTI $50.00-89.99 per bbl. At crude oil prices above $89.99 per bbl, a sliding scale formula - SPT Rate = 18% + 0.2% (Crude oil price - $90.00) - is applied. SPT is computed on gross income less allowances for royalty payments. The Green Fund Levy is charged at a rate of 0.1 percent on gross sales.

Under the terms of the Central Range Block PSCs, the government's share of "Profit Oil" will be collected in lieu of the royalty, PPL and SPT. There is no exemption from the Green Fund Levy. The Moruga property will be subject to royalties and all the other taxes and levies noted above.

Income Taxes

The fiscal regime in Trinidad & Tobago is an enhanced two-tier system consisting of the production-based royalty, PPL and SPT supported by a profits-based corporation tax which includes the Petroleum Profits Tax ("**PPT**") and an "Unemployment Levy". The PPT rate is 50 percent and the Unemployment Levy is 5 percent. Incentives and allowances are structured into the system to encourage investment, particularly in exploration projects and enhanced oil recovery schemes. PPT losses can be carried forward indefinitely. Costs of development and exploration are aggregated and deductible over five years.

Regulatory Regime

The petroleum industry in Trinidad & Tobago is principally governed by the *Petroleum Act* (1969) (the "**Petroleum Act**"), the *Petroleum Regulations* (1970) made thereunder, and the *Petroleum Taxes Act* (1974) (the "**Petroleum Taxes Act**"). The Petroleum Act establishes a framework for the grant of licences and contracts and for the conduct of petroleum operations, including activity on land and in submarine areas underlying the country's territorial waters. Under the Petroleum Act, the MEEA is responsible for determining the areas to be made available for petroleum operations, and may elect to invite applications for the rights to explore for and produce petroleum from these areas via competitive bidding. Persons wishing to engage in petroleum exploration and production operations must apply to the MEEA. On the basis of the Petroleum Act and its subsidiary regulations, the MEEA regulates and gives broad direction and guidance to the petroleum industry. The Petroleum Taxes Act is administered by the Minister of Finance through the Board of Inland Revenue and establishes the system of taxation for companies engaged in petroleum operations.

Private participation in the oil and natural gas industry in Trinidad & Tobago is undertaken under one of two fiscal regimes: E&P licences (otherwise known as royalty/tax concessions) and production sharing contracts. Both are currently in operation. The current licensing regime does not provide for compulsory state participation; however, Petrotrin and the National Gas Company have taken equity shares in some projects.

Market Conditions

Trinidad & Tobago's main oil pipeline network is focused on moving liquids from the fields in the Columbus Sub-basin, offshore Trinidad's east coast, to oil processing facilities at Galeota Point. After processing, the crude is piped via a 42-inch pipeline to dedicated tanker loading facilities. A smaller network carries crude produced off the south west coast to shore at Point Fortin. From there, the crude is piped via Petrotrin's onshore pipeline network to the Petrotrin refinery at Pointe-a-Pierre.

Trinidad & Tobago has one oil refinery, located at Pointe-a-Pierre in Trinidad. This facility manufactures oil products both for domestic use and for export. The plant is operated by Petrotrin and average throughput is approximately 150,000 bbl per day.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Parex. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. **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.**

In assessing the risks of an investment in the Common Shares, potential investors should realize that they are relying on the experience, judgment, discretion, integrity and good faith of the management of Parex. **An investment in Common Shares is suitable for only those investors who are willing to risk a loss of their entire investment and who can afford to lose their entire investment. Subscribers should consult their own professional advisors to assess the income tax, legal and other aspects of an investment in the Common Shares.**

Colombia

Parex Colombia has various working interests in numerous exploration blocks in the Llanos basin and one block in the Middle Magdalena. The contracts have exploration commitments and in some cases a portion of the commitments are guaranteed by issued letters of credit. Therefore Parex will be subject to additional risks associated with international operations in Colombia.

Guerrilla Activity in Colombia

A 40-year armed conflict between government forces and anti-government insurgent groups and illegal paramilitary groups, both thought to be funded by the drug trade, continues in Colombia. Insurgents continue to attack civilians and violent guerrilla activity continues in many parts of the country. The Putumayo region has been prone to guerrilla activity in the past. Pipelines have also been targets, including the Trans-Andean export pipeline which transports oil from the Putumayo region. The Catatumbo basin borders Venezuela and has historically been an area of high security risk where there continues to be guerrilla activity. Parex Colombia subsidiaries does not currently have interests in either the Putumayo region or Catatumbo basin. At present, the Company has its primary operations in the Llanos basin which has not experienced any significant anti-government insurgency conflict since the Company began operations in Colombia in 2009.

Since August 2012, there have been peace negotiations between the government and the Fuerzas Armadas Revolucionarias de Colombia ("**FARC**") guerrillas. The attempt by the president, Juan Manuel Santos, to end the 40-year conflict is intended to bring further institutional strengthening and development, particularly to rural regions. The government’s biggest challenge is perceived to be to ensure that the negotiations lead to a long-lasting peace and that demobilised members of the FARC rejoin civilian life, rather than regrouping in criminal bands.

Continuing attempts to reduce or prevent guerrilla activity may not be successful and guerrilla activity may disrupt Parex Colombia operations in the future. The Company may not be able to establish or maintain the safety of its operations and personnel in Colombia and this violence may affect its operations in the future. Continued or heightened security concerns in Colombia could also result in a significant loss to Parex and/or costs exceeding current expectations.

United States Relations with Colombia

Colombia is among several nations whose progress in stemming the production and transit of illegal drugs and is subject to annual certification by the President of the United States of America. Although Colombia has received a current certification, there can be no assurance that, in the future, Colombia will receive certification or a national interest waiver. The failure to receive certification or a national interest waiver may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;

- the Export-Import Bank of the United States and the Overseas Private Investment Company would not approve financing for new projects in Colombia;
- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes, and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with operations there. Any changes in the holders of significant government offices could have adverse consequences on Parex Colombia's relationship with the ANH and the Colombian government's ability to control guerrilla activities, and could exacerbate the factors relating to Parex Colombia's foreign operations. Any sanctions imposed on Colombia by the United States government could threaten Parex Colombia's ability to obtain any necessary financing to develop the Colombian properties. There can be no assurance that the United States will not impose sanctions on Colombia in the future, nor can the effect in Colombia that these sanctions might cause be predicted.

Canada relations with Colombia

The Canada-Colombia Free Trade Agreement became effective on August 15, 2011. Through the agreement, Canada’s producers and exporters benefit from reduced or eliminated tariffs on nearly all of Canada’s exports to Colombia. The agreement also provides a more predictable, transparent and rules-based trading environment for Canadian investors and businesses.

Trinidad & Tobago

Trinidad has a working interest in the Moruga Block. Therefore Parex will be subject to additional risks associated with international operations in Trinidad & Tobago.

Trinidad & Tobago has experienced relative prosperity and stability. Oil and natural gas resources and economic growth were part of the issues debated by the two main parties in the political arena. Future political stalemates could lead to indecision and inertia in the oil and natural gas regulatory arena which could adversely affect any oil and natural gas operations being carried out by the Company. As a result of limited infrastructure present in Trinidad & Tobago, land titles systems are not developed to the extent found in many more developed nations.

General

Commodity Prices, Markets and Marketing

Numerous factors beyond the Company's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Company. Accordingly, commodity prices are the Company’s most significant financial risk. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance the Company's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil, and natural gas. Many other aspects of the oil and natural gas business may also affect the Company. At present, crude oil sales are generally benchmarked against Brent reference prices.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States, Canada and Europe, the actions of Organization of Petroleum Exporting Countries ("**OPEC**"), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports, and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of the Company's reserves, borrowing capacity, revenues, profitability and cash flows from operations, and may have a material adverse effect on the Company's business, financial condition, results of operations, and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. The Company monitors market conditions and may selectively utilize derivative instruments to reduce exposure to crude oil price movements. However, the Company is of the view that it is neither appropriate or possible to eliminate 100 percent of its exposure to commodity price volatility.

Social Disruptions and Instability

Parex operates in Colombia and Trinidad & Tobago. In both countries companies operating in the oil and gas industry have experienced interruptions to their operations as a result of social instability and labour disruptions. For example, in January, 2012, the Company postponed the block LLA-30 exploration drilling program due to road blockades and civil disruption along the main road access to the block by groups with grievances against other operators in the area (not Parex). As a result, the Company had to delay drilling three exploration wells until 2013 and receive an extension of the initial exploration phase from the ANH.

The Company cannot provide assurances that this type of social instability or labour disruption will not be experienced in future. The potential impact of future social instability, labour disruptions and any lack of public order may have on the oil and gas industry in Colombia, and on our operations in particular, is not known at this time. This uncertainty may affect operations in unpredictable ways, including disruptions of fuel supplies and markets, ability to move equipment such as drilling rigs from site to site, or disruption of infrastructure facilities, including pipelines, production facilities, public roads, and off-loading stations, which could be targets or experience collateral damage as a result of social instability, labour disputes or protests. We may suffer loss of production, or be required to incur significant costs in the future to safeguard our assets against such activities, incur standby charges on stranded or idled equipment or to remediate potential damage to our facilities. There can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences. Further, these risks may not in any part be insurable in the event the Company does suffer damage.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves, and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties; production rates; ultimate reserve recovery; timing and amount of capital expenditures; marketability of oil and natural gas; royalty rates; and the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

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

Additional Financing

Depending on future exploration, development, acquisition and divestiture plans, Parex may require additional financing. The ability of Parex to arrange any such financing in the future will depend in part upon the prevailing capital market conditions, risk associated with the international operations, as well as the business performance of Parex. Periodic fluctuations in commodity prices may affect lending policies for potential future lenders. This in turn could limit growth prospects in the short run or may even require Parex to dedicate existing cash balances or cash flow, dispose of properties or raise new equity to continue operations under circumstances of declining energy prices, disappointing drilling results, or economic or political dislocation in foreign countries. There can be no assurance that Parex will be successful in its efforts to arrange additional financing on terms satisfactory to Parex. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. If additional financing is raised by the issuance of shares from treasury of Parex, control of Parex may change and shareholders may suffer additional dilution.

Conditions in the Oil and Natural Gas Industry

The oil and natural gas industry is intensely competitive and Parex will compete with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on an international basis.

The impact on the oil and natural gas industry from commodity price volatility is significant. During periods of high prices, producers may generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. The cost of purchasing land or properties and work commitments associated with new exploration blocks similarly can increase in price during these periods. During low commodity price periods, acquisition can costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers may also decline.

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration or development activities by Parex will result in discoveries of oil or natural gas that are commercially or economically feasible. It is difficult to project the costs of implementing any exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Parex' operations will be subject to all the risks normally associated with the exploration, development and operation of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, potential environmental damage, blow-outs, cratering, fires and spills, all of which could result in personal injuries, loss of life and damage to property of Parex and others. In accordance with customary industry practice, Parex will maintain insurance coverage, but will not be fully insured against all risks, nor are all such risks insurable.

Oil and natural gas exploration and development activities are dependent on the availability of seismic, drilling, completions and other specialized equipment 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 Parex and may delay exploration and development activities.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

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

The Company is exposed to a high level of exploration risk. The Company’s current and future (to the extent discovered or acquired) proved reserves will decline as reserves are produced from its properties unless the Company is able to acquire or develop new reserves. The business of exploring for, developing or acquiring reserves is capital-intensive and is subject to numerous estimates and interpretations of geological and geophysical data. There can be no assurance the Company’s future exploration, development and acquisition activities will result in material additions of proved reserves. To manage this risk, to the extent possible, Parex employs highly experienced geologists and geophysicists, uses technology such as 3D seismic as a primary exploration tool and focuses exploration efforts in known hydrocarbon-producing basins. In addition, the Company takes a portfolio approach to exploration by dispersing drilling locations among different exploration blocks and geological basins and by targeting multiple play-types. The Company may also choose to mitigate exploration risk through acquisitions that may require raising funds.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

Global Financial Markets

Market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader U.S. and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Company's ability to obtain equity or debt financing on acceptable terms.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Environmental Regulation and Risks

The Company is subject to environmental laws and regulations that affect aspects of the Company's past, present and future operations. Extensive national, provincial and local environmental laws and regulations in Colombia and Trinidad & Tobago will and do affect nearly all of the operations of Parex. These laws and regulations set various standards regulating certain aspects of health and environmental quality, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances; provide for penalties and other liabilities for the violation of such standards; and establish, in certain circumstances, obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation.

There is uncertainty around the impact of environmental laws and regulations, including those currently in force and proposed laws and regulations, and Parex cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered, interpreted from time to time, or enforced. It is not possible to predict the outcome and nature of certain of these requirements on the Company and its business at the current time; however, failure to comply with current and proposed regulations can have a material adverse impact on the Company's business and results of operations by substantially increasing its capital expenditures and compliance costs and its ability to meet its financial obligations, including debt payments. It may also lead to the modification or cancellation of operating licenses and permits, penalties and other corrective actions. Further, compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by Parex for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on Parex.

Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. The Company's activities have the potential to impair natural habitat, damage plant and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require the Company to obtain and comply with a variety of environmental registrations, licenses, permits and other approvals. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Company.

Significant liability could be imposed on Parex for costs resulting from potential unknown and unforeseeable environmental impacts arising from the Company's operations, including damages, clean-up costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased by Parex or non-compliance with environmental laws or regulations. While these costs have not been material to the Company in the past, there is no guarantee that this will continue to be the case in the future.

Given the nature of the Company's business, there are inherent risks of oil spills occurring at the Company's drilling and operations sites. Large spills of oil and oil products can result in significant clean-up costs. Oil spills can occur from operational issues, such as operational failure, accidents and deterioration and malfunctioning of equipment. In certain countries where the Company operates, oil spills can also occur as a result of sabotage and damage to the pipelines. Further, the Company sells oil at various delivery stations and the oil is truck transported. There is an inherent risk of oil spills caused by road accidents which the Company may still be deemed to be responsible for as the owner of the crude oil. All of these may lead to significant potential environmental liabilities, such as clean-up and litigation costs, which may materially adversely affect the Company's financial condition, cash flows and results of operations. Depending on the cause and severity of the oil spill, the Company's reputation may also be adversely affected, which could limit the Company's ability to obtain permits and affect its future operations.

To prevent and/or mitigate potential environmental liabilities from occurring, the Company has policies and procedures designed to prevent and contain oil spills. The Company works to minimize spills through a program of well designed facilities that are safely operated, effective operations integrity management, continuous employee training, regular upgrades to facilities and equipment, and implementation of a comprehensive inspection and surveillance system. Also, the Company's facilities and operations are subject to routine inspection by various Federal and Provincial authorities, in both Colombia and Trinidad and Tobago, to evaluate the Company's compliance with the various laws and regulations.

Gathering and Processing Facilities and Pipeline Systems

The Company delivers its products through gathering, processing and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. The Company currently produces oil in only one basin in Colombia that has seen an increase in crude oil production, but a decrease in crude take away capacity as heavier density crude production increases outpace lighter density crude production. Although pipeline expansions in Colombia are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows.

All of the Company's production is delivered for shipment on facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations, either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Company's ability to process its production and to deliver the same for sale.

Reliance on Third Party Operators

To the extent that the Company is not the operator of its properties, the Company will be dependent upon other guarantors or third parties' operations for the timing of activities and will be largely unable to control the activities and costs of such operators.

Natural Disasters and Weather-Related Risks

Parex will be subject to operating hazards normally associated with the exploration and production of oil and natural gas, including blowouts, explosions, oil spills, cratering, pollution, earthquakes, hurricanes and fires. The occurrence of any such operating hazards could result in substantial losses to Parex due to injury or loss of life and damage to or destruction of oil and natural gas wells, formations, production facilities or other properties.

The majority of oil in the Llanos basin in Colombia is delivered by two pipelines to the coastal export locations and refineries. Sales of oil could be disrupted by damage to these pipelines and/or road networks. Without other transportation alternatives, sales of oil could be disrupted by landslides or other natural events which impact these pipelines. If oil has to be trucked to the coastal export locations, operating and transport costs could materially increase.

Foreign Subsidiaries

Parex will conduct all of its operations in Trinidad & Tobago and Colombia through foreign subsidiaries and, in respect of Colombia, foreign branches. Therefore, to the extent of these holdings, Parex will be dependent on the cash flows of these subsidiaries to meet its obligations excluding any additional equity or debt Parex may issue from time to time. The ability of its subsidiaries to make payments and transfer cash to Parex may be constrained by, among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdiction in which it operates; and the introduction of foreign exchange and/or currency controls or repatriation restrictions, or the availability of hard currency to be repatriated.

Risks of Foreign Operations

Parex' operations may be adversely affected by changes in foreign government policies and legislation or social instability and other factors which are not within the control of Parex, including, but not limited to: nationalization, expropriation of property without fair compensation or marketable compensation, or renegotiation or nullification of existing concessions and contracts; the imposition of specific drilling obligations and the development and abandonment of fields; changes in energy and environmental policies or the personnel administering them; changes in oil and natural gas pricing policies; the actions of national labour unions; currency fluctuations and devaluations; currency exchange controls; economic sanctions; and royalty and tax increases and other risks arising out of foreign governmental sovereignty over the areas in which Parex' operations will be conducted, as well as risks of loss due to civil strife, acts of war, terrorism, guerrilla activities and insurrections. Parex' operations may also be adversely affected by laws and policies of Trinidad & Tobago and Colombia affecting foreign trade, taxation and investment. If Parex' operations are disrupted and/or the economic integrity of its projects is threatened for unexpected reasons, its business may be harmed. Prolonged problems may threaten the commercial viability of its operations.

In addition, there can be no assurance that contracts, licenses, license applications or other legal arrangements will not be adversely affected by changes in governments in foreign jurisdictions, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

In the event of a dispute arising in connection with Parex' operations in Trinidad & Tobago or Colombia, Parex may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgements in such other jurisdictions. Parex may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Parex' exploration, development and production activities in Trinidad & Tobago and Colombia could be substantially affected by factors beyond Parex' control, any of which could have a material adverse effect on Parex.

Acquiring interests and conducting exploration and development operations in foreign jurisdictions often require compliance with numerous and extensive procedures and formalities. These procedures and formalities may result in unexpected or lengthy delays in commencing important business activities. In some cases, failure to follow such formalities or obtain relevant evidence may call into question the validity of the entity or the actions taken. Management is unable to predict the effect of additional corporate and regulatory formalities which may be adopted in the future including whether any such laws or regulations would materially increase Parex' cost of doing business or affect its operations in any area.

Parex may in the future acquire oil and natural gas properties and operations outside of Trinidad & Tobago and Colombia, which expansion may present challenges and risks that Parex has not faced in the past, any of which could adversely affect the results of operations and/or financial condition of Parex.

Stage of Development

There are additional risks associated with an investment in Parex related to the early stage of Parex' development. These risks include, but are not limited to, availability of subsequent financing, complications and delays in establishment of operations in new jurisdictions, control of expenses, the ability to establish profitable operations, and other difficulties.

Security and Insurance

Colombia has a publicized history of security problems. The Company and its personnel are subject to these risks, but through effective security and social programs, Parex believes these risks can be effectively managed. The Company maintains insurance in an amount that it considers adequate and consistent with industry practice and its operations, however, it is difficult to obtain insurance coverage to protect against terrorist incidents and, as a result, the Company's insurance program excludes this coverage. Consequently, incidents like this in the future could have a material adverse impact on the Company's operations.

Legal Systems

Colombia is a civil law jurisdiction. Each of Barbados, Bermuda and Trinidad & Tobago, being part of the Commonwealth, has a similar legal system to Canada. There can be no assurance that joint ventures, licences, licence or permit applications or other legal arrangements will not be adversely affected by changes in governments, the actions of government authorities or others, or the effectiveness and enforcement of such arrangements.

Potential Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Company will be subject in connection with the operations of the Company. Some of the directors and officers are engaged and will continue to be engaged in the search for oil and natural 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. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Company, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, development, production, pricing, marketing and transportation). In Colombia, the oil and gas industry regulatory body is the ANH and in Trinidad & Tobago it is the MEEA. Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Company will require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Issuance of Debt

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

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.

Title to Assets

The acquisition of title to oil properties in the jurisdictions in which the Company operates is a detailed and time-consuming process. The Company's properties may be subject to unforeseen title claims. While the Company will diligently investigate title to all property and will follow usual industry practice in obtaining satisfactory title opinions and, to the best of the Company's knowledge, title to all of the Company's properties are in good standing, this should not be construed as a guarantee of title. Title to the properties may be affected by undisclosed and undetected defects.

Dilution

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

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. The price at which the Common Shares will trade cannot be accurately predicted.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Hedging

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or a sudden unexpected event materially impacts oil and natural gas prices. The Company may also enter into agreements to receive currencies at a fixed price or fix interest rates of floating rate based debt. Therefore, and as above with commodity hedging, there are risks associated with any currency or interest rate swap, or derivative agreement.

Litigation

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, related to, but not limited to, personal injuries, property damage, property tax, land rights, the environment and contractual disputes. The outcome of outstanding, pending or future proceedings, including the Lawsuit (as defined herein), 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 assets, liabilities, business, financial condition and results of operations. Without restriction, Parex, Parex Bermuda, and Ramshorn have been named as defendants in the Lawsuit. See *Legal Proceedings and Regulatory Actions.*

Breach of Confidentiality

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

Income Taxes

The Company and its subsidiaries file all required income tax returns and the Company believes that it is in full compliance with applicable Canadian, Colombian, Trinidad and Tobago, Barbadian, and Bermudian tax laws; however, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

Diversification

The Company's business focuses on the petroleum industry in Colombia. Other companies have the ability to manage their risk by diversification; however, the Company lacks diversification, in terms of the geographic scope of its business. As a result, factors affecting the industry or the regions in which it operates will likely impact the Company more acutely than if the Company's business was more diversified.

Expansion into New Activities

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

Accounting Adjustments

The presentation of financial information in accordance with IFRS requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the Company's consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the consolidated financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the Common Share price.

Lower oil and gas prices may increase the risk of write-downs of Parex' oil and gas property investments. Under IFRS, property, plant and equipment costs are aggregated into groups known as Cash Generation Units ("**CGU's**") for impairment testing. CGUs are reviewed for indicators that the carrying value of the CGU may exceed its recoverable amount. If an indication of impairment exists, the CGU's recoverable amount is then estimated. A CGU's recoverable amount is defined as the higher of the fair value less costs to sell and its value in use. If the carrying amount exceeds its recoverable amount an impairment loss is recoded to net earnings in the period to reduce the carrying value of the CGU to its recoverable amount. While these impairment losses would not affect cash flow, the charge to net earnings could be viewed unfavourably in the market.

Cash from Subsidiaries

The Company's ability to obtain cash from its foreign subsidiaries may be restricted. The Company currently conducts all of its operations through its foreign subsidiaries and foreign branches. Therefore, the Company will be dependent on the cash flows of these subsidiaries to meet its obligations. The ability of its subsidiaries to make payments to the Company may be constrained by among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdictions in which it operates; the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated; and contractual restrictions with third parties. Currently, there are no restrictions on the repatriation from Colombia of earnings to foreign entities; however, there can be no assurance that restrictions on repatriation of earnings from Colombia will not be imposed in the future.

Dependence on Management

The Chief Executive Officer and senior officers of the Company are critical to its success. In the event of the departure of the Chief Executive Officer or a senior officer, the Company believes that it will be successful in attracting and retaining qualified successors, but there can be no assurance of such success. If the Company is not successful in attracting and retaining qualified personnel, the efficiency of its operations could be affected, which could have a material adverse impact on the Company's future cash flows, earnings, results of operations and financial condition. The Company strongly depends on the business and technical expertise of its management team and there is little possibility that this dependence will decrease in the near term.

Ability to Attract and Retain Qualified Personnel

Recruiting and retaining qualified personnel is critical to the Company's success. The number of persons skilled in the acquisition, exploration, development and operation of oil and gas properties in the jurisdictions in which the Company operates is limited, and competition for such persons is intense. As the Company's business activity grows, it will require additional key financial, administrative, technical and operations staff. If Parex is not successful in attracting and training qualified personnel, the efficiency of its operations could be affected, which could have a material adverse impact on the Company's future cash flows, net income, results of operations and financial condition.

Corruption

The Company’s operations are governed by the laws of many jurisdictions, which generally prohibit bribery and other forms of corruption. The Company has policies in place to prevent any form of corruption or bribery, which includes enforcement of policies against giving or accepting money or gifts in certain circumstances and an annual certification from each employee confirming that each employee has received and understood the Company’s anticorruption policies. It is possible that the Company, some of its Subsidiaries, or some of the Company or its Subsidiaries' employees or contractors, could be charged with bribery or corruption as a result of the unauthorized actions of employees or contractors. If the Company is found guilty of such a violation, which could include a failure to take effective steps to prevent or address corruption by its employees or contractors, the Company could be subject to onerous penalties and reputational damage. A mere investigation itself could lead to significant corporate disruption, high legal costs and forced settlements (such as the imposition of an internal monitor). In addition, bribery allegations or bribery or corruption convictions could impair the Company’s ability to work with governments or nongovernmental organizations. Such convictions or allegations could result in the formal exclusion of the Company from a country or area, national or international lawsuits, government sanctions or fines, project suspension or delays, reduced market capitalization and increased investor concern. Further, from time to time the Company may acquire a company that subsequently is subject to a bribery or corruption charge, whereby the Company could assume onerous penalties and/or suffer reputational damage as a result of activities in which the Company had no part.

Risk Factors Relating to the Debentures

Existing and Prior Ranking Indebtedness

The Debentures are subordinate to Senior Indebtedness of the Company. The Debentures are also effectively subordinate to claims of creditors of the Company's Subsidiaries, except to the extent that the Company is a creditor of such Subsidiaries ranking at least *pari passu* with such creditors. In the event of the Company's insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up, its assets would be made available to satisfy the obligations of the creditors of such Senior Indebtedness before being available to pay the Company's obligations to the holders of the Debentures. Accordingly, all or a substantial portion of the Company's assets could be unavailable to satisfy the claims of the holders of the Debentures.

The Company's ability to meet its debt-service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the Company's financial performance, debt-service obligations, working capital and future capital-expenditure requirements. In addition, the Company's ability to borrow funds in the future and to make payments on outstanding debt will depend on the satisfaction of covenants in then existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Company's consolidated indebtedness could result in a default, which, if not cured or waived, could result in the acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the Company's assets would be sufficient to repay such indebtedness in full. There can also be no assurance that the Company will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

Repayment of the Debentures

The Company may not be able to refinance the principal amount of the Debentures in order to repay the principal outstanding, or may not have generated enough cash from operations to meet this obligation. The Company may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Debentures. There is no guarantee that the Company will be able to repay the outstanding principal amount in cash upon maturity of the Debentures and there is no requirement for the Company to establish a fund to provide for the ultimate repayment of the principal amount of the Debentures at expiry.

Prevailing Yields on Similar Securities

Prevailing yields on similar securities will affect the market value of the Debentures. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing yields for similar securities rise, and will increase as prevailing yields for similar securities decline.

Redemption on a Change of Control

The Company will be required to offer to purchase for cash all outstanding Debentures upon the occurrence of a Change of Control. However, it is possible that, following a Change of Control, the Company will not have sufficient funds at that time to make the required purchase of outstanding Debentures or that restrictions contained in other indebtedness will restrict those purchases. See *Description of Debentures – Repurchase Upon a Change of Control*. In addition, the Company's ability to purchase the Debentures in such an event may be limited by law, by the Indenture, by the terms of other present or future agreements relating to indebtedness, and agreements that the Company may enter into in the future which may replace, supplement or amend the Company's future debt. The Company's future credit agreements or other agreements may contain provisions that could prohibit the purchase of the Debentures by the Company. The Company's failure to purchase the Debentures would constitute an Event of Default under the Indenture, which might constitute a default under the terms of the Company's other indebtedness at that time.

If a holder of Debentures converts its Debentures in connection with a Change of Control, the Company may, in certain circumstances, be required to increase the conversion rate, as described under *Description of Debentures – Cash Change of Control*. While the increased conversion rate is designed, inter alia, to compensate a holder of Debentures for the lost option time value of its Debentures as a result of a Change of Control in certain circumstances, the increased conversion rate amount is only an approximation of such lost value and may not adequately compensate the holder for such loss. In addition, in some circumstances as described under *Description of Debentures – Cash Change of Control*, no adjustment will be made.

Absence of Covenant Protection

The Indenture does not restrict the Company or any of its Subsidiaries from incurring additional indebtedness or from mortgaging, pledging or charging its assets to secure any indebtedness. The Indenture does not contain any provisions specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving the Company or any of its Subsidiaries.

Redemption Prior to Maturity

The Debentures may be redeemed, at the option of the Company, on or after July 1, 2014 and prior to the Maturity Date at any time and from time to time, at a redemption price equal to the principal amount plus accrued and unpaid interest thereon, if any, up to but excluding the Redemption Date, provided that the Current Market Price of the Common Shares on the date on which notice of redemption is given is not less than 125 percent of the Conversion Price. See *Description of Debentures – Redemption and Purchase*. Holders of Debentures should assume that this redemption option will be exercised if the Company is able to refinance at a lower interest rate or it is otherwise in the interest of the Company to redeem the Debentures.

Dilutive Effects on Holders of Common Shares

The Company expects to issue Common Shares upon conversion, redemption or maturity of the Debentures. Additionally, the Company may issue Common Shares in connection with the payment of interest on the Debentures. Accordingly, holders of Common Shares may suffer dilution.

Conversion Right Following Certain Transactions

In the event of certain transactions, pursuant to the terms of the Indenture, each Debenture will become convertible into securities, cash or property receivable by a holder of Common Shares in such transactions. This change could substantially reduce or eliminate any potential future value of the conversion privilege associated with the Debentures. For example, if the Company were acquired in a cash merger, each Debenture would become convertible solely into cash and would no longer be convertible into securities whose value would vary depending on future prospects and other factors. See *Description of Debentures – Conversion Privilege*.

Credit Risk

The likelihood that purchasers of the Debentures will receive payments owing to them under the terms of the Debentures will depend on the Company's financial health and creditworthiness at the time of such payments.

Tax Laws

The Indenture does not contain a requirement that the Company increase the amount of interest or other payments to holders of Debentures in the event that the Company is required to withhold amounts in respect of income or similar taxes on payment of interest or other amounts on the Debentures. At present, no amount is required to be withheld from such payments to holders of Debentures, but no assurance can be given that, in the future, applicable income tax laws or treaties will not be changed in a manner that may require the Company to withhold amounts in respect of tax payable on such amounts.

ADDITIONAL INFORMATION

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

SCHEDULE "A"

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

Management of Parex Resources Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

The Operations and Reserves Committee of the board of directors of the Company has

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

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

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

The Operations and Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and natural 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 data and other oil and gas information;

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

(c) the content and filing of this report.

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

(signed) "*Wayne Foo*"
Wayne Foo
President and Chief Executive Officer

(signed) "*Kenneth Pinsky*"
Kenneth Pinsky
Chief Financial Officer

(signed) "*Norman McIntyre*"
Norman McIntyre
Chairman

(signed) "*John Bechtold*"
John Bechtold
Chairman of Operations and Reserves Committee

DATED as of this 19th day of March, 2014.

SCHEDULE "B"

FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Parex Resources Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves, probable reserves, and proved plus probable plus possible reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Reserves Evaluator	**Description and Preparation Date of Evaluation Report**	**Location of Reserves**	**Net Present Value of Future Net Revenue (before income tax, 10% discount rate)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
			M$	**M$**	**M$**	**M$**
GLJ Petroleum Consultants Ltd.	February 20, 2014	Colombia	0	1,140,735	0	1,140,735

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

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

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

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, dated February 20, 2014.

GLJ Petroleum Consultants Ltd.

Per: (signed) "*Keith M. Braaten*"
Keith M. Braaten, P. Eng.

SCHEDULE "C"

PAREX RESOURCES INC.
FINANCE AND AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

1. Overall Purpose & Objectives

A standing committee of the Board of Directors of Parex Resources Inc. (the "Corporation") consisting of members of the Board is hereby appointed by the Board from amongst its members and complying with all other legislation, regulations, agreements, articles and policies to which the Corporation and its business is subject is hereby established and designated the Audit Committee (hereinafter referred to as the "Audit Committee" or the "Committee").

The Audit Committee will assist the Board in fulfilling its oversight responsibilities, including without limitation the review, approval or recommendation to the Board for approval, of:

- the Corporation's financial statements, management's discussion and analysis and the integrity of the financial reporting process,
- the management of financial and other enterprise risks,
- the external audit process and the Corporation's process for monitoring compliance with financial laws and regulations,
- any material disclosure of information to shareholders, security regulators and the public, including, without limitation, the Corporation's annual information form; and
- significant acquisitions and divestitures.

The Audit Committee shall also take the steps necessary to address and resolve all instances or allegations of fraud reported to the Audit Committee.

2. Composition

(a) This Audit Committee shall be composed of at least three individuals appointed by the Board from amongst its members. The Audit Committee shall appoint one member as Committee Chair.

(b) All members of the Audit Committee shall be Board members who are not members of management of the Corporation. Subject to certain exemptions that may be available under applicable securities legislation, all members of the Audit Committee must be "independent", as defined in National Instrument 52-110 – *Audit Committees* as adopted by the Canadian Securities Regulatory Authorities ("NI 52-110").

(c) A quorum shall be a majority of the members of the Committee.

(d) Members of the Audit Committee must be financially literate, as defined in NI 52-110, and at least one member must have accounting or related financial management expertise.

3. Meetings

(a) The Audit Committee shall meet at least quarterly with Management, and at least annually with the external auditors, such meetings generally coinciding with the release of interim or year-end financial information.

(b) Effective agendas, with input from Management, shall be circulated to Committee members and relevant Management personnel along with background information on a timely basis prior to the Committee meetings.

(c) Minutes of each meeting shall be prepared.

(d) The meetings and proceedings of the Audit Committee shall be governed by the provisions of the by-laws of the Corporation that regulate meetings and proceedings of the Board.

(e) The Audit Committee may invite the Chief Executive Officer or Chief Financial Officer or his designate(s), such Directors, Officers or employees of the Corporation, the Corporation's external auditor(s) and any other independent external advisors or consultants as it may see fit to attend its meetings and take part in the discussion and consideration of the affairs of the Audit Committee.

4. Reporting / Authority

(a) Following each meeting, the Audit Committee will report to the Board and provide a summary of the meeting.

(b) Copies of the minutes from all meetings, as well as information and supporting schedules reviewed and discussed by the Audit Committee at any meeting shall be retained and made available for examination by the Board or any Director upon request to the Chair.

(c) The Audit Committee shall have the authority to investigate any activity of the Corporation falling within the terms of this Mandate, and may request any employee of the Corporation to cooperate with any request made by the Audit Committee.

(d) The Audit Committee may retain external persons having special expertise and obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation and approve the terms of retainer and the fees payable to such parties.

5. Duties & Responsibilities

(a) **Financial Information and Shareholder Communication**

(i) Review:

(i) The audited annual financial statements and unaudited quarterly financial statements with Management and the external auditors (including disclosures under "Management's Discussion & Analysis"), in conjunction with the report of the external auditors, and obtain explanation from Management of all material variances between comparative reporting periods. Upon satisfactory completion of the review, the Committee will recommend that the Board of Directors approve the annual and quarterly financial statements and Management's Discussion and Analysis.

(ii) Shareholder communications based on the quarterly and annual financial statements, including, without limitation, all annual and interim earnings press releases.

(iii) The Corporation's annual information form.

(iv) Significant accounting and tax compliance issues where there is choice among various alternatives or where application of a policy has a material effect on the financial results of the Corporation.

(b) **Internal Controls**

(ii) Review annually and approve as required:

(i) Processes adopted by Management for establishing effective internal controls, to be responsible for the accurate reporting of the Corporation's revenues and expenses, and the safeguarding of its assets.

(ii) Internal control systems maintained by the Corporation.

(iii) Major changes to management information systems.

(iv) Spending authority and approval of limits.

(c) **Enterprise Risk Management**

(iii) Review periodically the Corporation's:

(i) Risk assessment and risk management policies.

(ii) Hedging strategies, policies, objectives and controls.

(iii) Risk retention philosophy and resulting exposure to the Corporation.

(iv) Loss prevention policies and programs in the context of competitive and operational consideration.

(v) Insurance programs.

(vi) Directors' and Officers' insurance coverage.

(vii) Procedures for the control, identification and reporting of fraudulent acts.

(d) **External Auditors**

(i) Annually:

(A) Recommend to the Board of Directors an independent accounting firm to conduct the annual audit.

(B) Review with Management and auditors the purpose and scope of the audit examination, review the terms of the external auditors' engagement and set the fees for the annual audit.

(C) Assess the qualifications, performance and independence of the auditors, taking into account the opinions of Management, and present conclusions to the Board.

(D) Obtain and review a report by the external auditors describing: the firm's internal quality control procedures; any material issues raised by the most recent internal quality control review (or peer review) of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm and any steps taken to deal with such issues.

(E) Obtain a certificate attesting to the external auditors' independence, which identifies all relationships between the external auditors and the Corporation.

(F) Review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Instrument 51-102 as adopted by the Canadian Securities Regulatory Authorities ("NI 51-102"), on a routine basis, whether or not there is a change of auditors.

(G) Meet independently with auditors in the absence of Management to discuss any issues which the auditors may wish to bring forward including any restrictions imposed by Management or significant accounting issues in which there was a disagreement with Management.

(ii) Where there is a change of auditor, review all issues related to the change, including information to be included in the notice of change of auditors (NI 51-102) and the planned steps for an orderly transition.

(iii) Generally oversee the work of the external auditor, including resolving any issues that arise between Management and the external auditors.

(iv) Pre-approve engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

(e) **Audit**

(i) Review with Management and the external auditors major issues regarding accounting principles and financial statement presentation, including any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of Management that may be material to financial reporting.

(ii) Question Management and the external auditors regarding significant financial reporting issues during the fiscal period and the method of resolution of such issues.

(iii) Monitor the steps taken by management to deal with issues arising from the annual audit.

(iv) Review the auditors' report to Management, containing recommendations of the external auditors', and Management's response and subsequent remedy of any identified weaknesses.

(v) Prepare an Audit Committee report as may be required by the relevant securities commissions to be included in the Corporation's annual Management Proxy Circular.

(f) **Press**

(iv) Review of press releases and other publicly circulated documents containing financial information or financial guidance.

(g) **Legal**

(v) Review annually the legal expenses incurred by the Corporation.

(h) **Budget and Forecast of Operations**

(i) Be responsible for the Corporation having in place a process to review all general and administrative expenditures (including income tax) to improve future planning and cost control.

(ii) Be responsible for the Corporation having in place a process to review all material capital investments to assess where value has been created and improve future decisions.

(i) **New Business Development**

(vi) Review of proposed acquisitions and divestitures at the request of the Board, including a review of the financial and legal due diligence conducted, and make recommendations to the Board as to the completion of such transactions.

(j) **Audit Committee Evaluation and Complaints**

(vii) Periodically, in conjunction with the Corporate Governance Committee:

(viii) Assess individual Audit Committee member and Chair performance and evaluate the performance of the Audit Committee as a whole, including its processes and effectiveness.

(ix) Review the Corporation's procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters.

(x) Review the Corporation's procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

(xi) Develop and approve Audit Committee member eligibility criteria, identify Directors qualified to become Committee members and recommend appointments to and removals from the Audit Committee.

6. Other Duties & Responsibilities

(a) The Audit Committee shall be available to meet with any member of Management or any employee of the Corporation who wishes to raise any concern with respect to conflicts of interest and ethical issues.

(b) The responsibilities, practices and duties of the Audit Committee outlined herein are not intended to be comprehensive. The Board may, from time to time, charge the Audit Committee with the responsibility of reviewing items of a financial, control or risk management nature

7. Mandate Review

The Board shall review this Mandate every other year, or more frequently as may be determined necessary by the Board, to ensure that it is achieving its purpose.

8. Authorization

This Audit Committee mandate is hereby approved on behalf of the Board of Directors of Parex Resources Inc. this 30th day of October, 2009 as amended on November 9, 2011 and November 13, 2013.