ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2021

MARCH 1, 2022

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ABBREVIATIONS, CONVENTIONS AND OTHER INFORMATION

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

Oil and Natural Gas Liquids

bbl(s)	barrel(s)
bbl(s)/d	barrels of oil per day
mbbl	one thousand barrels
MMbbls	one million barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	one million cubic feet
Mcfe	thousand cubic feet equivalent
Mcf/d	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
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
MMbtu	one million British thermal units
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.

This Annual Information Form contains certain oil and gas metrics, including operating netbacks, which do not have standardized meanings or standard methods of calculation under NI 51-101 and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

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 ("m^3")	0.028
cubic metres	cubic feet	35.301
bbls	m^3	0.159
m^3	bbls	6.29
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, 2021.

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 (being the average of the daily noon buying rates during the 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 1, 2022, the closing buying rate for one U.S. dollar in Canadian dollars as certified by the Bank of Canada was 1.2708.

	Year Ended December 31		
	2021	**2020**	**2019**
Highest rate during the period	1.2942	1.4496	1.3600
Lowest rate during the period	1.2040	1.2718	1.2988
Average closing rate for the period	1.2535	1.3415	1.3269
Rate at the end of the period	1.2678	1.2732	1.2988

NON-GAAP AND OTHER FINANCIAL MEASURES

This AIF uses various "non-GAAP financial measures", "non-GAAP ratios", "supplementary financial measures" and "capital management measures" (as such terms are defined in NI 52-112). Such measures are not standardized financial measures under GAAP and might not be comparable to similar financial measures disclosed by other issuers. Such Non-GAAP measures should not be considered as alternatives to, or more meaningful than measures determined in accordance with GAAP. These measures facilitate management's comparisons to the Company's historical operating results in assessing its results and strategic and operational decision-making and may be used by financial analysts and others in the oil and natural gas industry to evaluate the Company's performance. Further, management believes that such financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Company's principal business activities.

Please refer to the 2021 MD&A "Non-GAAP and Other Financial Measures Advisory", which is available at the Company's website at www.parexresources.com and on the Company's profile on SEDAR at www.sedar.com for additional information about such financial measures, including reconciliations to the nearest GAAP measures, as applicable.

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% 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;

"**ANH**" means the Agencia Nacional de Hidrocarburos;

"**Board of Directors**" means the board of directors of the Company;

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

"Convenio" means the ANH contract for direct operated areas from Ecopetrol with similar terms and conditions to the E&P Contract except for the non-application of economic rights and allowance for the production period to last until the economic limit of the respective field;

"**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;

"**Ecopetrol**" means Ecopetrol S.A.;

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

"E&P Contracts" means the exploration and production contracts entered by and between Parex Colombia and the ANH.

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

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

"**Material Subsidiary**" means: (i) a direct or indirect subsidiary of Parex which has total assets that exceed 10% of the consolidated assets of Parex; (ii) a direct or indirect subsidiary of Parex which has revenues that exceed 10% of the consolidated revenues of Parex; and (iii) when the direct or indirect subsidiaries that satisfy (i) and (ii) are aggregated together, such direct or indirect subsidiaries have total assets that exceed 20% of the consolidated assets of Parex and revenues that exceed 20% of the consolidated revenues of Parex;

"MD&A" means the Company's Management's Discussion and Analysis of the financial condition and results of operations of the Company for the three months and year ended December 31, 2021 and 2020 dated March 1, 2022;

"**NCIB**" has the meaning ascribed thereto under *General Development of the Business - Normal Course Issuer Bid*;

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

"NI 52-112" means National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure;

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

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

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

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

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

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

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

"**Verano**" or "**Verano Energy**" means Verano Energy Limited, a corporation organized under the laws of Alberta;

"**Verano Arrangement**" means the acquisition by Parex of all of the Verano Shares pursuant to a plan of arrangement carried out by Verano under the ABCA;

"**Verano Limited**" means Verano Energy Limited, a corporation organized under the laws of Barbados and redomiciled to Bermuda in September 2019; and

"**Verano Shares**" means the common shares in the capital of Verano.

Selected Oil and Gas Terms

"**abandonment and reclamation costs**" means all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

"**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" maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time;

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

"**crude oil**" or "**oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas;

"**CSA 51-324**" means Staff Notice 51-324 - *Revised 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);

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs;

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

"**GLJ Report**" means the report of GLJ dated February 3, 2022 evaluating the oil and natural gas reserves of the Company as at December 31, 2021;

"**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;

"**heavy crude oil**" or "**heavy oil**" means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity;

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur;

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

"**light crude oil**" or "**light oil**" means crude oil with a relative density greater than 31.1 degrees API gravity;

"**medium crude oil**" or "**medium oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases;

"**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates;

"**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;

"**property**" includes: (a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer). A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas;

"**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 category (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's**") 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 anticipated termination date of the NCIB and the expectation that the Company will initiate a new NCIB;
- Parex' expectations that it will conduct an evaluation program on the La Belleza discovery by drilling one exploration well;
- the anticipated total work commitment on the Company's newly awarded blocks;
- that Parex does not anticipate that environmental protection requirements will have a significant financial or operational effect on Parex' capital expenditures, earnings or competitive position;
- the anticipated effect of environmental protection requirements;
- the anticipated impact of environmental protection requirements;
- forecasted abandonment and reclamation costs and the anticipated timing thereof;
- the timing of land that will be relinquished;
- timing of development of undeveloped reserves and the estimated future capital spending to develop such undeveloped reserves;
- that 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;
- that the Company does not anticipate any significant economic factors or significant uncertainties will affect any particular components for the Reserves Data;
- forecasted future development costs and the anticipated timing thereof;
- the Company's hedging activities;
- the estimated total inflated, undiscounted amount required to settle asset retirement obligations in respect of the Company's producing and non-producing wells and facilities and the anticipated timing thereof;
- the estimated total inflated, undiscounted amount required to settle its environmental obligations and the anticipated timing thereof;
- estimated volumes of gross and net production in 2022;
- anticipated growth in Colombia's GDP in 2022 and 2023;
- expectations that Parex' non-audit fees will be reduced in 2022;
- the size of, and future net revenues from, oil and natural gas reserves;
- the performance characteristics of the Company's oil and natural gas properties;
- supply and demand for oil and natural gas;
- development and drilling plans, including completion, testing, and tie in of wells and the anticipated timing thereof;

- 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;
- tax horizon and future tax rates enacted in the Company's areas of operation;
- the quantity of the Company's reserves;
- potential impacts of community unrest;
- the Company's plans to sell gas produced from Block LLA-32, Aguas Blancas Field, Capachos-Andina Field and La Belleza Field, the duration thereof and the contract price;
- expected costs outside the Company's contractual obligations;
- the Company's risk management program;
- the Company's oil and natural gas production levels; and
- 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.

Statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future. The 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 and Barbados; volatility in market prices for oil, NGLs and natural gas; the impact of significant declines in market prices for oil, NGL's and natural gas; the impact of the COVID-19 pandemic and the ability of the Company to carry on its operations as currently contemplated in light of the COVID-19 pandemic; 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 and Barbados; 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 and Colombia; risks associated with negotiating with foreign governments as well as country risk associated with conducting international activities; 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; that the Company will not initiate a new NCIB; that environmental protection requirements will have a significant financial or operational effect on Parex' capital expenditures, earnings or competitive position; costs in connection with abandonment and reclamation, asset retirement obligations and environmental obligations will be greater than anticipated; that Parex' non-audit fees will not be reduced in 2022; the risks discussed in the MD&A 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; the impact (and the duration thereof) that the COVID-19 pandemic will have on (i) the demand for crude oil and conventional natural gas; (ii) the supply chain, including the Company's ability to obtain the equipment and services it requires; and (iii) the Company's ability to produce, transport and/or sell its crude oil and conventional natural gas; 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 funds flow from operations, 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 natural 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; that Parex will have sufficient financial resources to repurchase shares under its NCIB; 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 and investors 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 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." On January 1, 2016, Parex amalgamated with its wholly owned Subsidiary, Verano Energy Limited, to form Parex Resources Inc. On March 1, 2022, Parex amalgamated with its wholly owned Subsidiary, Parex Resources Holdings Ltd., to form 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 2700, 585 - 8th Avenue S.W., Calgary, Alberta T2P 1G1.

The Company is a reporting issuer in each of the Provinces of Canada and the Common Shares trade on the TSX under the symbol "PXT".

Intercorporate Relationships

As at the date hereof, the Company has six direct or indirect wholly-owned 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.

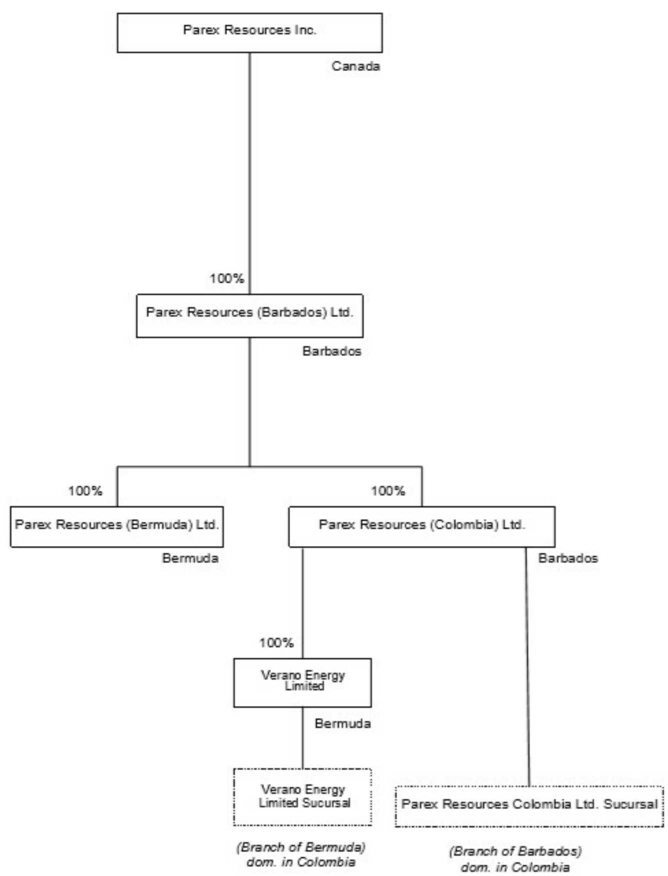
The following chart sets forth, as of the date hereof, the name of each Material Subsidiary, the jurisdiction of incorporation and laws of incorporation, the registered holder of the voting shares of each Material Subsidiary, the percentage of voting shares held and the business conducted by each Material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

Name of Subsidiary	Jurisdiction of Incorporation and Laws of Incorporation	Registered Holder of Voting Securities and Percentage Held	Business Conducted
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%)	The majority of the Company's activities in Colombia are conducted through a Colombian branch of this entity.
Parex Resources (Bermuda) Ltd.	Bermuda (*Companies Act 1981*)	Parex Barbados (100%)	Holding company.
Verano Energy Limited	Bermuda (*Companies Act 1981*)	Parex Colombia (100%)	The majority of the Company's activities in Colombia are conducted through a Colombian branch of this entity.

Parex provides certain administrative, management and technical support services to certain of its Subsidiaries pursuant to administrative, management, technical support service, and other agreements. The Company currently has administrative, management and technical support service agreements with Parex Colombia and Verano Limited in order to provide these Subsidiaries with support services from Canada.

Corporate Structure

The following chart illustrates the organizational structure of the Company, including its Material Subsidiaries as of the date hereof, this chart does not include all the Subsidiaries of the Company:



The Company's organizational structure facilitates its business as a multi-jurisdictional company whose operations are located outside of Canada. Parex has two Subsidiaries active in Colombia whose activities 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.

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 and Bermuda also have a banking system and advisory services (legal and accounting) that are comparable to North America. Barbados has a tax treaty with Canada. Bermuda has a disclosure tax agreement with Canada. Colombia has a free trade agreement and a tax convention with Canada.

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

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a description of the events that have influenced the general development of the business of Parex and its subsidiaries during the years ended December 31, 2019, 2020 and 2021. For a more detailed description of the business and operations of Parex and its Material Subsidiaries, see *Description of the Business and Operations* in this Annual Information Form.

Parex' Activities in Colombia

During the years ended December 31, 2019, 2020 and 2021, Parex, primarily through its subsidiary, Parex Colombia, has participated in ANH's bid rounds and has also entered into farm-in agreements and completed various acquisitions of working interests in blocks located in Colombia. See *Description of the Business and Operations - Parex Resources (Colombia) Ltd*. in this Annual Information Form.

Normal Course Issuer Bid

On December 23, 2019, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 13,986,994 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The Company also entered into an automatic share purchase plan with a broker to facilitate repurchases of Common Shares pursuant to the Company's NCIB. As of December 17, 2020, Parex purchased for cancellation the maximum number of shares under the NCIB and the NCIB formally terminated on December 22, 2020.

On December 23, 2020, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 12,868,562 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The Company entered into an automatic share purchase plan with a broker to facilitate repurchases of Common Shares pursuant to the Company's NCIB. Parex purchased for cancellation the maximum number of shares under the NCIB and the NCIB formally terminated on December 22, 2021.

On January 4, 2022, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 11,820,533 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The NCIB will terminate on January 3, 2023 and subject to TSX approval, Parex expects, at such time, to initiate a new NCIB. The Company also entered into an automatic share purchase plan with a broker to facilitate repurchases of Common Shares pursuant to the Company's NCIB. Under the Company’s automatic share purchase plan, the Company’s broker may repurchase Common Shares under the NCIB during the Company’s self-imposed blackout periods.

Operational Activities

For a description of the Company's exploration, development and production activities in 2019, 2020 and 2021, 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, 2019

- achieved annual average oil and natural gas production in 2019 of 52,687 boe/d (consisting of 7,214 bbls/d of light crude oil and medium crude oil, 44,494 bbls/d of heavy crude oil and 5,874 Mcf/d of conventional natural gas), an increase of 19% over average 2018 production volumes of 44,408 boe/d (consisting of 4,668 bbls/d of light crude oil and medium crude oil, 39,120 bbls/d of heavy crude oil and 3,720 Mcf/d of conventional natural gas);
- realized Brent referenced average sales price of $54.70/boe(1) and an operating netback of $37.51/boe(2);
- recognized net income of 328.0 million;
- generated funds flow from operations in 2019 of $570.5 million(1)($3.90 per share basic);
- incurred capital expenditures of $208.2 million(1); and
- participated in drilling 43 gross wells in Colombia resulting in 38 oil wells, 1 abandoned well, 2 suspended wells and 2 wells under test, for a success rate of 97%.

Year ended December 31, 2020

- achieved annual average oil and natural gas production in 2020 of 46,518 boe/d (consisting of 6,021 bbls/d of light crude oil and medium crude oil, 39,197 bbls/d of heavy crude oil and 7,800 Mcf/d of conventional natural gas), a decrease of 12% over average 2019 production volumes of 52,687 boe/d;
- realized Brent referenced average sales price of $32.55/boe(1) and an operating netback of $20.84/boe(1);
- recognized net income of $99.3 million;
- generated funds flow from operations in 2020 of $297.0 million(1)($2.15 per share basic);
- incurred capital expenditures of $141.3 million(1); and
- participated in drilling 30 gross wells in Colombia resulting in 25 oil wells, 2 abandoned well, 2 wells under test and 1 pressure maintenance well, for a success rate of 93%.

Year ended December 31, 2021

- achieved annual average oil and natural gas production in 2021 of 46,998 boe/d (consisting of 6,831 bbls/d of light crude oil and medium crude oil, 38,449 bbls/d of heavy crude oil and 10,308 Mcf/d of conventional natural gas), an increase of 1% over average 2020 production volumes of 46,518 boe/d;
- realized Brent referenced average sales price of $60.97/boe(1) and an operating netback of $42.53/boe(2);
- recognized net income of $303.1 million;
- generated funds flow from operations in 2021 of $577.5 million(3)($4.61 per share basic)(2);
- incurred capital expenditures of $277.2 million(1); and
- participated in drilling 49 gross wells in Colombia resulting in 34 oil wells, 1 abandoned wells, 4 wells under test and — pressure maintenance well, for a success rate of 85%.

(1) Supplementary Financial Measure (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory" contained within the Company's 2021 MD&A for the composition of such measure.
(2) Non-GAAP ratio (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory" contained within the Company's 2021 MD&A for the composition of such measure..
(3) Capital Management Measure (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory" contained within the Company's 2021 MD&A for the composition of such measure.
(4) Non-GAAP financial measure(as defined in NI 52-112) . See "Non-GAAP and Other Financial Measures Advisory" contained within the Company's 2021 MD&A for the composition of such measure.

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, however at present all of the Company's oil and natural gas production and reserves are located in Colombia.

The following is a summary of the business and operations of Parex and each of its Material Subsidiaries domiciled in Bermuda and Barbados, with branches in Colombia. See also *General Development of the Business - Parex' Activities in Colombia* and *Principal Properties* in this Annual Information Form.

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% of the voting shares of Parex Trinidad. Parex Barbados currently holds 100% of the voting shares of Parex Colombia and Parex Bermuda and no longer holds any shares of Parex Trinidad as this entity was sold in 2015. Parex Barbados also facilitates future capitalization of its subsidiaries.

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 oil exploration and development activities in Colombia.

Since inception Parex Colombia acquired various exploration blocks in Colombia through a combination of ANH bid rounds, farm-in agreements with industry partners and acquisitions. Exploration blocks acquired in this time frame that are considered material are described below.

PARI participated in the Colombia Mini Bid Round of 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% 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 ANH, Parex Colombia and CESC. Pursuant to the E&P 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.

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.), resulting in Parex Colombia holding a 100% interest in the 2008 Blocks and assuming the letters of credit to the ANH in respect of the additional 50% of the work commitments for the 2008 Blocks.

On March 16, 2012, Parex Colombia entered into a farm-in agreement with Cepsa Colombia S.A. for the Cabrestero block of Colombia (the "**Cabrestero Block**"). PACLS fulfilled the farm-in commitment in July 2012 and earned a 50% working interest in the Cabrestero Block. In December 2012, PACLS received ANH recognition of the farm-in and as operator of the Cabrestero Block. On May 31, 2013, Parex Colombia completed the purchase of the remaining 50% working interest in the Cabrestero Block from its partner in the block, for $12.5 million before adjustments.

On May 5, 2014, Parex Colombia signed a farm-in agreement with Ecopetrol, subject to the execution of the *Covenio Contract* with ANH, for the joint development of the Capachos block in the northern foothills of the Llanos Basin (the "**Capachos Block**"). The *Convenio Contract* with ANH was awarded to Ecopetrol on June 30, 2015, fulfilling a key condition of the farm-in agreement. Pursuant to the terms of the farm-in agreement, Parex Colombia paid 100% of the cost of two wells in the Capachos Block to re-activate the field and earned a 50% working interest and operatorship of the block. In the second quarter of 2018, Parex completely fulfilled its farm-in commitments.

On July 23, 2014, Parex Colombia successfully participated in the 2014 Colombia Bid Round and was awarded a 100% working interest in Block VMM-9 in the Middle Magdalena Basin of Colombia ("**Block VMM-9**") and Block VIM-1 in the interior Magdalena Basin of Colombia ("**Block VIM-1**").

On September 18, 2014, Parex Colombia signed an E&P Contract with the ANH for Block VMM-9. Block VMM-9 is approximately 152,314 gross acres in size and is subject to an initial base royalty of 9%. The first phase of the agreement has a term of 36 months, which has since been extended, and a current commitment of approximately $89 million. Currently the E&P Contract is suspended due the lack of regulations to explore and exploit unconventional hydrocarbons.

On September 18, 2014, Parex Colombia signed an exploration and production agreement with the ANH for Block VIM-1. Block VIM-1 is approximately 223,651 gross acres in size and is subject to an initial base royalty of 25% for conventional deposits. Work on Block VIM-1 commenced in 2017, by acquiring 3D seismic. The Apure-1 exploration well was drilled in the third quarter of 2018. Subsequently Parex farmed out 50% of its working interest in return for the farmee to pay the first $10 million of the La Belleza exploration well in the fourth quarter of 2019. Parex Colombia entered Phase 2 of the E&P Contract with a $26 million commitment, consisting on the drilling of two exploratory wells. On December 31, 2020, Parex received regulatory approval to extend the Block VIM-1 boundaries by 32,000 acres to the east, onto adjacent open lands, which extension is based on the estimated extent of the 2020 La Belleza discovery.

On September 29, 2015, Parex Colombia signed a participation agreement with Ecopetrol whereby Parex Colombia will farm-in to operate and earn a 50% working interest in the Aguas Blancas light oil field located in the Middle Magdalena Basin of Colombia (the "**Aguas Blancas Field**"), subject to ANH approval. The agreement requires investment by Parex Colombia, during the initial earning phase of three years, of approximately $61.2 million through undertaking delineation drilling and a waterflood pilot program at Parex Colombia's sole cost to earn a 50% working interest in the Aguas Blancas Field revenues. Subsequently, all future capital investment provides Ecopetrol with a 10% carry in such capital investment by way of Parex Colombia being required to spend 60% and Ecopetrol 40%, with revenues and operating costs being based on the parties' respective 50% working interest. The initial earning phase had a term of 3 years ending on or before September 29, 2019. By the end of 2018, Parex fulfilled its farm-in commitment.

On April 27, 2016, Parex Colombia signed two farm-in agreements with Ecopetrol whereby Parex Colombia will farm-in to operate and earn a 50% working interest in each of the De Mares block ("**De Mares Block**") and Boranda block (formerly Playon block) ("**Boranda Block**") located in the Middle Magdalena Basin of Colombia, both subject to ANH approval. Parex committed to fund 100% of a work-over of a well for an estimated cost of $3 million to earn a 50% working interest and operatorship of the De Mares Block. Subsequent to such work-over, Parex and Ecopetrol have the option to drill an additional exploration well with Parex paying 100% of the costs. Parex fulfilled the farm-in agreement for the De Mares Block by drilling, completing and stimulating the Coyote 2 well by April 2018. Parex committed to fund 100% of the estimated drillings costs of $7 million for an exploration well to earn a 50% working interest in and operatorship of, the Boranda Block. The Boranda-1 well was drilled in November 2016 and Parex and Ecopetrol drilled the Boranda-2 and 3 wells in 2019.

On October 4, 2017, Parex Colombia completed the acquisition of a partner's 17.5% working interest in Block LLA-32 **("Block LLA-32")** and 50% working interest in Block LLA-40 **("Block LLA-40")** for net cash consideration of $5.0 million and the assumption of the future decommissioning liabilities.

On June 29, 2018, Parex signed a farm-in agreement with Hupecol Meta LLC for the exploration area of Block CPO -11 in the Llanos Basin of Colombia ("**Block CPO-11**"). Pursuant to the terms of the farm-in agreement, Parex will pay 100% of the costs to drill two explorations wells and acquire 108 kilometers of 2D seismic to earn a 50% working interest, subject to government approval. The farm-in agreement includes approximately 570,000 gross acres subject to a royalty of approximately 30% which is calculated on a net basis. Parex has fulfilled all the farm-in commitments by drilling the Anacona-1 well and the Montuno-1 well.

On October 18, 2018, Parex Colombia completed the acquisition of 100% working interest in the Fortuna Block (the "**Fortuna Block"**) from Emerald Energy PLC Sucursal Colombia and Geoadinpro S.A.S for net cash consideration of $17 million. The Fortuna Block is located in the Middle Magdalena Basin of Colombia and is governed by an Ecopetrol Association Contract which is subject to a total royalty of approximately 15% and was approved on March 19, 2019. The Cayena well was drilled in November 2020 and long-term testing started on this well in December 2020.

On February 18, 2019, Parex and Verano signed a private agreement with Geopark Colombia SAS by which it farmed down its working interest in the exploration area in Block LLA -32 from a combined 87.5% working interest to 75% working interest in exchange for the set off of an outstanding amount between the parties.

On March 7, 2019, Parex signed a farm-in agreement with Cepsa Colombia S.A. for the Block Merecure exploration area in the Llanos Basin of Colombia (**"Block Merecure"**). Pursuant to the terms of the farm-in agreement, Parex will pay 100% of the costs to drill two explorations wells to earn a 35% working interest, subject to government approval. The farm-in agreement includes approximately 570,000 gross acres subject to a royalty of approximately 30% which is calculated on a net basis. As part of the farm-in commitments, the Tamariniza-1 exploration well was drilled by Parex in the second quarter of 2019.

On June 4, 2019, Parex Colombia successfully participated in the June 2019 ANH Permanent Process for the Assignment of Areas **("PPAA")** bid round - first cycle and was awarded a 100% working interest in Block LLA-94 in the Llanos Basin of Colombia ("**Block LLA-94**") and Block VSM-25 in the upper Magdalena Basin of Colombia ("**Block VSM-25**").

On November 26, 2019, Parex Colombia successfully participated both for its own account and jointly with Ecopetrol in the December 2019 ANH PPAA bid round - second cycle and was awarded a 50% operating working interest in Block LLA-122 in the Llanos Basin of Colombia ("**Block LLA-122**"), and a 100% working interest in Block VSM-36 in the upper Magdalena Basin of Colombia ("**Block VSM-36**") and in Block VMM-46 in the middle Magdalena Basin of Colombia ("**Block VMM-46**").

On December 12, 2019, Parex Colombia assigned a 50% non-operated working interest in Block LLA-94 to Geopark Colombia SAS which was approved on May 27, 2020.

On December 1, 2020, Parex was awarded two prospective blocks **("Block LLA-134")** and **("Block VIM-43")** under the third cycle of the ANH PPAA bid round. The total work commitment on the newly awarded blocks is approximately $3.8 million to acquire 95km2 of 3D seismic.

On July 7, 2021 Parex, Parex and Ecopetrol executed agreements whereby Parex will earn an operated, 50% interest in two blocks, the Arauca block **(the "Arauca Block")** and the LLA-38 block **("Block LLA-38")**, located in the proven and highly prolific Llanos basin in the Arauca province of northeastern Colombia. Collectively, the blocks contain proved reserves along with development and drill ready exploration prospects. Parex and Ecopetrol have agreed to an initial work plan for the blocks, funded solely by Parex, that consists of the drilling of 2 development wells, 1 exploration well and a further capital program of $75.8 million. The overall timing and activities of the capital program, across both the blocks, will be determined based on partner consultation, customary regulatory approvals, surface access and exploration success, among other factors.

On December 22, 2021, Parex was awarded 18 prospective blocks **in the Colombia** bid round, **("Blocks LLA-122, LLA-113, LLA-4-1, LLA-74, LLA-16-1, LLA-43-1, LLA-95, LLA-81 and LLA-111")**, **("Blocks CPO11-2, CPO-4-1 and CPO-10)**, **("Block CPE 2-2")**, **("Block VIM 10-2")**, **("Block VMM 4-2")**, **("Blocks VSM-37, VSM-14-1 and VSM-13-2)**. The total work commitment on the newly awarded blocks is approximately $101.6 million.

See *Principal Properties*.

Parex Resources (Bermuda) Ltd.

Parex Bermuda was incorporated on April 9, 2012 under the *Companies Act* of Bermuda.

On April 12, 2012, Parex Bermuda entered into a purchase and sale agreement with a Bermuda based company, Nabors Global Holdings II (the "**Seller**") and completed the acquisition of the class A shares of the Seller's wholly owned subsidiary, Ramshorn, the operations of which included interests in five exploration blocks located in Llanos Basin, including Block LLA-34 **("Block LLA-34")** and Block LLA-32, and two blocks located in Middle Magdalena Basin in Colombia for a total of approximately 567,000 gross acres (276,000 net acres). The consideration paid for the shares of Ramshorn was approximately $71.8 million in cash, including customary closing adjustments, which were funded from cash on hand. Parex also assumed $17.7 million of letters of credit related to Ramshorn's interests post closing.

See *Principal Properties*.

Verano Energy Limited and its Subsidiaries

Verano was formed by the amalgamation of P1 Energy Corp. and APO Energy Inc. on December 20, 2010 under the provisions of the *Business Corporations Act* (Ontario) to form "P1 Energy Corp.". On May 26, 2011, Verano was continued out of Ontario and into Alberta under the ABCA. On September 5, 2013, Verano changed its name from P1 Energy Corp. to Verano Energy Limited. Verano was formed for the purpose of carrying out (through its foreign subsidiaries) the acquisition, exploration, development and production of oil and gas properties in Colombia. All of the Verano Shares were acquired by Parex pursuant to the Verano Arrangement.

At the time of completion of the Verano Arrangement, Verano's direct and indirect foreign subsidiaries consisted of: (i) P1 Energy Holdings Inc., Verano Energy Holdings (Barbados) Limited, P1 Energy Sigma Corp. and Verano Energy (Barbados) Ltd. (now Verano Limited), each of which were formed pursuant to the *Companies Act* of Barbados; (ii) Verano Energy Corp., which was formed pursuant to the Laws of Panama; and (iii) Verano Energy S.A.S., which was formed pursuant to the *Companies Act* of Colombia (collectively, the "**Verano Entities**"). The Verano Entities had been engaged in the acquisition, exploration, development and production of oil and gas properties in Colombia. As a result of the amalgamation of Parex and Verano on January 1, 2016, the Verano Entities are now direct and indirect subsidiaries of Parex and the only Verano Entities that continue to actively engage in business are Verano Limited and its operating branch in Colombia.

The primary assets of Verano Limited and its operating branch in Colombia at the time of the Verano Arrangement consist of working interests and oil and natural gas reserves in ANH exploration contracts in respect of Llanos Basin Block LLA-32 and Block LLA-34.

See *Principal Properties*.

Competitive Conditions

There is considerable competition in the worldwide oil and natural gas industry, including in 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* in the MD&A.

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. The Company has adopted an Anti-Bribery and Anti-Corruption Policy. See *Risk Factors* in the MD&A.

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.

Reorganization

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 as noted below. See *Corporate Structure - Intercorporate Relationships*.

In September 2019, Verano Limited (formerly Verano Energy (Barbados) Limited), redomiciled to Bermuda and changed its name. This was part of Parex' ongoing improvement of its organizational tax structure.

Employees

The following table details the Company's employees by country as of December 31, 2019, 2020 and 2021:

	Number of Employees		
	2021	**2020**	**2019**
Canada (Calgary)	62	51	44
Colombia	309	297	295
Total	**371**	**348**	**339**

The Company employs individuals with various professional skills in the course of pursuing its business plan. These professional skills include, but are not limited to, geology, geophysics, engineering, financial, legal and business skills. Drawing on its experience in the oil and gas business, Parex believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; and capital markets expertise. This approach allows Parex to effectively identify, evaluate and execute on its business plan.

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 2022. The Company is exposed to potential environmental liability in connection with its business of oil and natural gas exploration and production. See *Risk Factors* in the MD&A.

Trends in Environmental Regulation

The Company is of the opinion that it is reasonably likely that in its areas of operation 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, 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* in the MD&A.

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, for all blocks. 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 2021, expenditures for normal compliance with environmental regulations, as well as expenditures beyond normal compliance, were as set out in the Company's audited annual financial statements for the year ended December 31, 2021, which have been filed on SEDAR.

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 Health, Safety and Environment 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 and 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.

Annually, the Company discloses on its website certain environmental, social and governance ("**ESG**") performance data on material ESG issues. The Company produces a fulsome sustainability report in accordance with sustainability reporting standards and documenting the Company's assessment of risks, opportunities, progress and challenges as they relate to sustainability issues. The content and methods used in the Company's sustainability disclosures are informed by the Sustainability Accounting Standards Board, the Task Force on Climate-related Financial Disclosures (**"TCFD"**), the Global Reporting Institute Standards and the Carbon Disclosure Project. The most recent scorecard, the 2020 Sustainability Report and the Company's inaugural TCFD Report dated December 20, 2021 are available on the Company's website.

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 generally well received by the local communities and have contributed to maintaining a positive relationship in the areas in which the Company operates. However, the Company may from time to time experience production curtailments, or delays of capital programs as a result of community unrest, which could materially negatively affect its operations and financial results. See *Risk Factors* in the MD&A.

PRINCIPAL PROPERTIES

As at December 31, 2021, the Company's principal land holdings and exploration blocks, excluding blocks that the Company is planning to relinquish, were as follows:

	Working Interest	Gross Acres[(1)]	Net Acres[(2)]
Colombia Llanos Basin			
Operated Properties			
Block Arauca[(3)]	50%	41,071	20,536
Block LLA 4-1[(5)]	100%	118,769	118,769
Block LLA-16-1[(5)]	100%	185,523	185,523
Block LLA-26	100%	93,376	93,376
Block LLA-30	100%	1,451	1,451
Block LLA-32	87.5%	23,757	20,787
Block LLA-38[(3)]	50%	117,566	58,783
Block LLA-40	100%	4,072	4,072
Block LLA-43-1[(5)]	100%	191,269	191,269
Block LLA-74[(5)]	100%	148,263	148,263
Block LLA-81[(5)]	100%	244,846	244,846
Block LLA-94	50%	89,175	44,588
Block LLA-95[(5)]	100%	214,841	214,841
Block LLA-111[(5)]	100%	600,226	600,226
Block LLA-112[(5)]	100%	775	775
Block LLA-113[(5)]	100%	4,557	4,557
Block LLA-122	50%	188,298	94,149
Block LLA-134	100%	147,937	147,937
Cabrestero Block	100%	9,212	9,212
Capachos Block	50%	64,073	32,037
CPE 2-2 Block[(5)]	100%	732,703	732,703
CPO 4-1 Block[(5)]	100%	14,826	14,826
CPO-10 Block[(5)]	100%	735,141	735,141
CPO-11 Block[(3)]	50%	489,617	244,809
CPO 11-2 Block[(5)]	100%	6,101	6,101
Los Ocarros Block	100%	30,562	30,562
Non-Operated Properties			
Block LLA-34	55%	63,528	34,940
Colombia Magdalena Basin			
Operated Properties			
Aguas Blancas	50%	13,386	6,693
Block VIM-1	50%	139,575	69,788
Block VIM-10-2[(5)]	100%	335,017	335,017
Block VIM-43	100%	90,457	90,457
Block VMM-4-2[(5)]	100%	102,288	102,288
Block VMM-9	100%	152,412	152,412
Block VSM-13-2[(5)]	100%	228,450	228,450
Block VSM-25	100%	68,221	68,221
Block VSM-36	100%	148,263	148,263
Block VSM-37[(5)]	100%	119,543	119,543
Block VSM-41-1[(5)]	100%	207,500	207,500
Block VMM-46	100%	111,026	111,026
Boranda Block	50%	43,367	21,684
De Mares Block	50%	174,387	87,194
Fortuna Block[(4)]	100%	26,205	26,205
Total		6,521,632	5,809,820

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 earnings terms and/or regulatory approval.
(4) Subject to Ecopetrol's right to back-in as per the association contract (20%).
(5) Awarded in 2021 Colombia Bid Round and executed on January 18, 2022.

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

Colombia

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

Block LLA-34 (55% working interest)

Parex obtained its 55% interest in Block LLA-34 through the purchase of the class A shares of Ramshorn by Parex Bermuda in April 2012 (45% working interest) and the purchase of the Verano Shares pursuant to the Verano Arrangement in June 2014 (10% working interest). This block is adjacent to Block LLA-32 (see below). During 2012, Parex and its partners drilled the Tua prospect at Block LLA-34 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 decided that further drilling at Tarotaro and Max were to be postponed allowing for focus on the development of Tigana and Tua. In 2014, Parex and its partners delineated the Tigana field by drilling an additional 6 wells, 5 of which are producers and 1 that is an injector. An additional 5 wells were drilled at Tua in 2015, further delineating the pool and resulting in 4 oil producers with 1 injector well. In 2015, Parex and its partners successfully tested 1 new field, being the Tilo field, and drilled 2 new fields at Jacana and Chachalaca. Tilo is comprised of Guadalupe formation reservoir producing heavy crude oil at 13.5º API. Jacana has both Mirador formation (untested) and Guadalupe with the Guadalupe on production producing heavy crude oil at 15º API. The Chachalaca field encountered several intervals in the Mirador formation reservoir with first tested zone producing 31º API light crude oil. In 2016, 4 wells were drilled in Jacana as delineation wells and all were tested resulting in 4 producing Guadalupe wells. Three Guadalupe development wells were also drilled in Tigana, resulting in 3 producing wells. Additionally, Parex drilled an exploration well at Chiricoca, which after testing, was put on production in the Mirador formation at 31º API oil. In 2017, Parex continued to delineate the Jacana, Tigana Norte and Tigana pools, participating in the drilling of 23 wells in 2017 resulting in 21 producing wells, 1 well dry and abandoned and 1 water disposal well. In 2018, Parex continued to delineate and develop the Tigana and Jacana pools and discovered a new accumulation at Tigui participating in the drilling of 26 wells resulting in 25 producing oil wells and one well dry and abandoned. Also in 2018 an oil flowline was substantially built to connect oil production from Block LLA-34 to the Colombia export pipeline system, providing an additional egress option for oil production from this block. In 2019, Parex continued to delineate and develop the Tigana and Jacana pools and discovered a new accumulation at Gauco, participating in the drilling of 27 wells resulting in 25 producing oil wells and two under test. Also in 2019, an oil flowline was constructed and commissioned to connect oil production from the Jacana field to the Colombia export pipeline system, providing an additional egress option for oil production from this Block. In 2020, Parex continued to delineate and develop the Tigana and Jacana pools, participating in the drilling of 19 wells resulting in 19 producing oil wells. Average net oil production from Block LLA-34 in 2020 was 33,917 bbl/d net (consisting of 628 bbl/d light crude oil and medium crude oil and 33,289 bbl/d of heavy crude oil) or 61,667 boe/d gross (consisting of 1,142 bbl/d light crude oil and medium crude oil and 60,525 bbl/d of heavy crude oil). Also in 2020, the Tigana oil field flowline tie in was completed to the Colombia export pipeline system.

In 2021, Parex continued to delineate and develop the Tigana and Jacana pools and extend the Tigui oil field, participating in the drilling of 19 wells resulting in 19 producing oil wells. Average net oil production from Block LLA-34 in 2021 was 30,784 bbl/d net (consisting of 302 bbl/d light crude oil and medium crude oil and 30,482 bbl/d of heavy crude oil) or 55,971 boe/d gross (consisting of 549 bbl/d light crude oil and medium crude oil and 55,422 bbl/d of heavy crude oil).

Cabrestero Block (100% working interest)

In 2012, Parex farmed into the Cabrestero Block and drilled the Kitaro-1 well to earn a 50% interest in the block, and on May 31, 2013, Parex completed the purchase of its partner's 50% working interest in the Cabrestero Block..

In 2016, the Bacano-1 exploration well was drilled on the Cabrestero Block but due to mechanical problems, the well did not reach target formation and was abandoned. In the fourth quarter of 2016, Parex re-drilled the Bacano prospect from a new pad to minimize horizontal deviation and successfully drilled the Bacano-2 well. The well has since tested, and is producing heavy oil from the Guadalupe formation at 17º API. In 2017, Parex drilled wells Bacano 3, 4, and 5 which were all successful and placed on production and an exploration well Bacano 6 was drilled but was dry and abandoned. In 2018, Parex drilled ten wells at Cabrestero resulting in six producing oil wells, three injection wells and one dry and abandoned well. The drilling results identified an extension to the Akira pool that was appraised in 2019. In 2019, Parex drilled 7 wells, Bacano Oeste-1, 2, 5 and Akira 12, 13, 14 and 17. With the exception of the Bacano Oeste-5 well that could not be completed due to mechanical failure in the wellbore, all wells drilled are oil producing wells. The Bacano Oeste-5 well was abandoned in 2020. In 2020, Parex drilled 6 wells on the Cabrestero Block; Bacano Oeste-3, 4 and Akira 19, 20, 21 and 22. All wells drilled are oil producing wells.

In 2021, Parex drilled 13 wells on the Cabrestero Block; Bacano 9 and 22, Bacano Oeste-6, 7, 9, 10, 11 and 13, Bacano Sur-1 and 2, Bacano Suroeste-1, Totoro Oeste-1 and Totoro Sur-1. All wells drilled are oil producing wells or water injection wells to allow a field waterflood pressure maintenance scheme.

Average net oil production from the Cabrestero Block in 2021 was 6,946 bbl/d net (6,946 bbl/d gross) consisting entirely of heavy crude oil.

Capachos Block (50% working interest)

In 2014, Parex, farmed into the Capachos Block and drilled Capachos-2 and Capachos Sur-2 exploration wells in the second quarter of 2018 to earn a 50% working interest and operatorship of the block. In 2019, Parex drilled 2 wells, Andina Norte-1 and Andina-3, and commenced the construction of a natural gas processing facility. In 2020, Parex did not drill any wells on the Capachos Block, and focused on finishing the construction of the natural gas processing facility on this Block.

In 2021, Parex did not drill any wells on the Capachos Block.

Average net oil production from the Capachos Block in 2021 was 4,347 boe/d net (consisting of 4,085 bbl/d of light crude oil and medium crude oil and 1,569 Mcf/d of conventional natural gas) or 8,694 boe/d gross (consisting of 8,170 bbl/d light crude oil and medium crude oil and 3,138 Mcf/d of conventional natural gas).

Block LLA-32 (87.5% working interest)

Parex obtained its original 30% interest in Block LLA-32 through the purchase of the class A shares of Ramshorn by Parex Bermuda in April 2012. Parex obtained an additional 40% through the purchase of Verano pursuant to the Verano Arrangement in June 2014 and an additional 17.5% from a purchase of a partners interest in October 2017. Block LLA-32 is immediately north of Block LLA-34.

In 2019, Parex drilled the Azogue-1 exploration well resulting in a discovery in the Guadalupe and Mirador reservoirs. The Guadalupe reservoir was placed on production on long term test and a tie in to the Kananaskis facilities was completed in 2020. In 2020, Parex did not drill any wells on Block LLA-32 and focused on completing the Azogue field flowline.

In 2021, Parex drilled three wells on Block LLA-32; Azogue-1, Groot-1 and Carcayu-1 resulting in one oil well. Groot-1 and Carcayu-1 were subsequently abandoned.

Average net oil production from Block LLA-32 in 2021 was 2,266 boe/d net (consisting of 1,022 bbl/d of light crude oil and medium crude oil and 7,461 Mcf/d of conventional natural gas) or 2,590 boe/d gross (consisting of 1,168 bbl/d of light crude oil and medium crude oil and 8,527 Mcf/d of conventional natural gas).

Block LLA-26 (100% working interest)

In 2014, Parex, by way of three separate transactions, consolidated a 100% interest in the LLA-26 block in the Llanos Basin of Colombia **("Block LLA-26")** and accepted the commitment to drill an exploration well to retain the block.

In 2021, no development activities were conducted on Block LLA-26 other than facility optimization for the existing producing field.

Average oil production from Block LLA-26 in 2021 was 1,045 bbl/d net (1,045 bbl/d gross) consisting entirely of heavy crude oil.

Summary of Block Commitments as of March 1, 2022

The following information represents the gross outstanding financial commitments of the Company per block in accordance with the E&P Contracts/Convenios, all of which are in Colombia.

Blocks	Exploration Phase	Current Phase Expiry Date	Outstanding Gross Financial Commitment	Outstanding Net Financial Commitment	Current Commitment
VSM-25	Phase 0	Suspended	$ 18,848,768	$ 18,848,768	Seismic + 1 exploration well
VSM-36	Phase 0	6/21/2022	$ 11,527,680	$ 11,527,680	Seismic
LLA-94	Phase 1	10/1/2023	$ 21,801,472	$ 10,900,736	Seismic + seismic reprocessing + 3 exploration wells
LLA-122	Phase 1	10/5/2023	$ 8,623,514	$ 4,311,757	Seismic + seismic reprocessing
LLA-134	Phase 1	07/12/2024	$ 2,426,880	$ 2,426,880	Seismic
VIM-1	Phase 2/PEV	01/30/2023	$ 6,100,000	$ 3,050,000	1 appraisal well
VIM-43	Phase 0	07/30/2024	$ 2,123,520	$ 2,123,520	Seismic
VMM-9	Phase 1	Suspended	$ 89,090,800	$ 89,090,800	Seismic + 5 exploration wells
VMM-46	Phase 1	10/13/2023	$ 10,213,120	$ 10,213,120	Seismic
De Mares*	Second Retention Period	3/29/2022	$ 7,000,000	$ 3,500,000	1 exploration well
De Mares*	Evaluation Program	12/19/2021	$ 2,400,000	$ 1,200,000	Seismic
CPE-2-2	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
CPO-4-1	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
CPO-10	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
CPO-11-2	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-4-1	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-16-1	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-43-1	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-74	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-81	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-95	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-111	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-112	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-113	Phase 0	1/18/2024	$ 5,844,736	$ 5,844,736	1 exploration well
VIM-10-2	Phase 0	1/18/2024	$ 5,066,112	$ 5,066,112	1 exploration well
VMM-4-2	Phase 0	1/18/2024	$ 5,197,568	$ 5,197,568	1 exploration well
VSM-13-2	Phase 0	1/18/2024	$ 3,842,560	$ 3,842,560	1 exploration well
VSM-14-1	Phase 0	1/18/2024	$ 3,842,560	$ 3,842,560	1 exploration well
VSM-37	Phase 0	1/18/2024	$ 7,685,120	$ 7,685,120	2 exploration wells
LLA-38	Phase 1	Suspended	$ 56,666,666	$ 56,666,666	Seismic + 1 exploration well
Arauca**	N/A	N/A	$ 83,534,000	$ 83,534,000	2 development wells + work program to be agreed with partner
CPO-11	Phase 2 Subsequent Exploration Program	10/30/2022	$ 2,500,000	$ 1,250,000	1 exploration well
TOTAL			$ 424,471,908	$ 400,259,415	

***Relinquishment plus transfer of commitments requested. Pending ANH approval.**

****Farm-in commitment**

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, 2021. The effective date of the Reserves Data is December 31, 2021 and the preparation date of the Reserves Data is January 19, 2022. 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 3, 2022 with an effective date of December 31, 2021. The Reserves Data summarize the oil, natural gas and NGL 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, 2021. Nearly all of the Company's oil production and 87% of the oil, natural gas and NGL proved plus probable reserves are located in the Llanos Basin of Colombia with the remaining oil reserves and production located in the Magdalena Basin. The Company does not have any coal bed methane, synthetic crude oil, bitumen, gas hydrates, shale gas, synthetic gas, or tight oil production or reserves.

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 is 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 Health, Safety and Environment 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 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, natural gas and NGL 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 the MD&A.

In general, estimates of economically recoverable crude oil, natural gas and NGL 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, natural gas and NGL 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* in the MD&A.

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, 2021
FORECAST PRICES AND COSTS

Reserve Category	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent[2]	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	7,428	6,491	68,860	58,625	24,492	20,470	189	175	80,559	68,703
Developed Non-Producing	2,067	1,786	7,122	6,087	2,732	2,537	40	40	9,684	8,336
Undeveloped	12,197	10,455	21,756	18,240	4,593	4,499	303	282	35,022	29,727
TOTAL PROVED	21,693	18,732	97,739	82,952	31,817	27,507	531	497	125,266	106,765
TOTAL PROBABLE	21,589	18,248	45,582	35,533	36,886	30,058	241	224	73,560	59,015
TOTAL PROVED PLUS PROBABLE	43,282	36,980	143,321	118,485	68,703	57,565	773	721	198,825	165,781
TOTAL POSSIBLE	31,259	25,672	46,688	38,735	59,047	47,776	314	292	88,102	72,662
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	74,541	62,652	190,009	157,220	127,749	105,341	1,086	1,012	286,927	238,441

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) See *Abbreviations, Conventions and Other Information*.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2021
FORECAST PRICES AND COSTS

Reserves Category	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)[1]					Unit Value Before Income Tax Discounted at 10%/ year[2]	
	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)	($/Mcfe)
PROVED												
Developed Producing	3,340,204	2,822,359	2,451,687	2,175,427	1,962,399	2,455,334	2,074,466	1,801,167	1,597,247	1,439,930	35.69	5.95
Developed Non-Producing	396,239	322,800	270,878	232,631	203,489	257,279	208,744	174,419	149,153	129,925	32.50	5.42
Undeveloped	1,231,707	938,673	739,851	599,573	497,033	794,151	590,814	452,933	356,069	285,708	24.89	4.15
TOTAL PROVED	4,968,150	4,083,832	3,462,417	3,007,631	2,662,921	3,506,764	2,874,024	2,428,519	2,102,469	1,855,563	32.43	5.41
PROBABLE	2,960,339	1,974,723	1,418,900	1,077,713	853,345	1,929,702	1,269,571	899,434	673,699	526,238	24.04	4.01
TOTAL PROVED PLUS PROBABLE	7,928,489	6,058,555	4,881,317	4,085,344	3,516,266	5,436,467	4,143,596	3,327,953	2,776,168	2,381,801	29.44	4.91
POSSIBLE	4,027,957	2,498,194	1,717,101	1,268,736	986,725	2,612,746	1,608,401	1,096,001	802,844	619,267	23.63	3.94
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	11,956,446	8,556,749	6,598,418	5,354,080	4,502,991	8,049,212	5,751,997	4,423,954	3,579,012	3,001,068	27.67	4.61

Notes:

(1) Net present values prepared by GLJ in the evaluation of Parex' oil and natural gas properties are calculated by considering sales of oil and natural gas, reserves, processing of third party reserves and other income. After tax net present values prepared by GLJ in the evaluation of Parex' oil and natural gas 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.

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

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2021
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)(2)	Future Net Revenue Before Future Income Taxes ($000's)	Future Income Taxes(1) ($000's)	Future Net Revenue After Future Income Taxes ($000's)(1)
PROVED	7,794,369	1,159,075	1,212,300	372,030	82,814	4,968,150	1,461,385	3,506,764
PROVED PLUS PROBABLE	12,593,316	2,107,767	1,916,503	539,829	100,728	7,928,489	2,492,022	5,436,467
PROVED PLUS PROBABLE PLUS POSSIBLE	18,397,688	3,131,220	2,536,244	658,425	115,353	11,956,446	3,907,233	8,049,212

Notes:
(1) Values are calculated by utilizing existing tax pools for Parex in the evaluation of Parex' properties and taking into account current Colombian federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Parex' Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2021.
(2) See *Significant Factors and Uncertainties - Abandonment and Reclamation Costs*.

FUTURE NET REVENUE
BY PRODUCT TYPE(5)
as at December 31, 2021
FORECAST PRICES AND COSTS

	Net Present Value of Future Net Revenue (before deducting Future Income Tax Expenses and Discounted at 10%/year) (M$)	Unit Value (before deducting Future Income Tax Expenses and Discounted at 10%/year) (($/bbl)/($/Mcf))(3)(4)	
		($/bbl)	($/Mcf)
Proved Reserves			
Light Crude Oil and Medium Crude Oil(1)	589,516	28.06	4.68
Heavy Crude Oil(1)	2,802,970	33.79	5.63
Conventional Natural Gas(2)	69,931	24.94	4.16
Total Proved	3,462,417	32.43	5.41
Proved Plus Probable			
Light Crude Oil and Medium Crude Oil(1)	1,024,384	28.35	4.72
Heavy Crude Oil(1)	3,623,647	30.58	5.10
Conventional Natural Gas(2)	196,323	20.28	3.38
Total Proved Plus Probable	4,844,355	29.48	4.91
Proved Plus Probable Plus Possible			
Light Crude Oil and Medium Crude Oil(1)	1,604,192	28.41	4.74
Heavy Crude Oil(1)	4,630,887	28.21	4.70
Conventional Natural Gas(2)	291,830	19.28	3.21
Total Proved Plus Probable Plus Possible	6,526,909	27.69	4.61

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
(4) Unit values are based on net reserve volumes.
(5) The Company did not separately detail the future net revenue of NGL reserves as the volumes were immaterial.

Pricing Assumptions

Crude Oil

The following table sets forth the benchmark reference prices, as at December 31, 2021, 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, 2021
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	ICE Brent ($US/bbl)	Inflation Rates[2] (%/Year)	Exchange Rate[3] ($US/$Cdn)
Forecast[4]				
2022	73.00	76.00	—	0.790
2023	69.01	72.51	3.0	0.790
2024	67.24	71.24	2.0	0.790
2025	68.58	72.66	2.0	0.790
2026	69.96	74.12	2.0	0.790
2027	71.35	75.59	2.0	0.790
2028	72.78	77.11	2.0	0.790
2029	74.24	78.66	2.0	0.790
2030	75.72	80.22	2.0	0.790
2031	77.24	81.83	2.0	0.790
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, 2021.

Natural Gas

Natural gas produced from the Calona, Carmentea and Kananaskis Fields in Block 32 is sold to other blocks for use as fuel gas. The contract price is $6.00 per MMBtu for 3.0 MMcfpd in 2022. The remaining gas production will be sold at $4.20 per MMBtu. Solution gas produced in the Aguas Blancas Field is to be sold at a contract price of $2.00 per Mcf up to 1.0 MMcfpd, all remaining gas production will be sold at $1.50 per Mcf. For the Capachos-Andina Field, produced gas is to be sold at a contract price of $2.20 per MMBtu, while butane volumes are sold at a contract price of $30.00 per bbl. For the La Belleza Field, produced gas is sold at a contract prices (less transportation and compression fees) of $4.00 per MMBtu in the proved scenario and $5.00 per MMBtu in the proved plus probable scenario. In 2021 Parex realized an average price of $6.11/mcf.

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, 2021 against such reserves as at December 31, 2020 based on forecast prices and cost assumptions. All of the Company's evaluated reserves are located in Colombia.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
As at December 31, 2021
FORECAST PRICES AND COSTS[1]

	Light Crude Oil And Medium Crude Oil			**Heavy Crude Oil**		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2020	16,433	14,897	31,330	105,524	45,317	150,842
Discoveries	—	—	—	—	—	—
Extensions[2]	1,777	2,604	4,380	5,294	4,108	9,402
Improved Recovery	—	—	—	—	—	—
Technical Revisions[3]	3,480	(1,423)	2,056	811	(3,849)	(3,038)
Acquisitions[4]	2,246	5,568	7,814	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	139	(57)	83	143	5	149
Production	(2,382)	—	(2,382)	(14,034)	—	(14,034)
December 31, 2021	21,693	21,589	43,282	97,739	45,582	143,321

	Conventional Natural Gas			**BOE**		
FACTORS	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2020	34,637	35,864	70,501	128,083	66,407	194,491
Discoveries	—	—	—	—	—	—
Extensions[2]	3,644	1,390	5,034	7,886	7,028	14,914
Improved Recovery	—	—	—	—	—	—
Technical Revisions[3]	(2,737)	(399)	(3,136)	3,916	(5,398)	(1,481)
Acquisitions[4]	—	—	—	2,246	5,568	7,814
Dispositions	—	—	—	—	—	—
Economic Factors	36	31	67	289	(46)	242
Production	(3,763)	—	(3,763)	(17,154)	—	(17,154)
December 31, 2021	31,817	36,886	68,703	125,266	73,559	198,825

Notes:
(1) The Company did not separately detail an NGL reserves reconciliation as the volumes were immaterial.
(2) Reserve extensions are associated with the evaluations of the LLA-34 and Capachos blocks.
(3) Technical revisions are associated with the evaluation of additions on the Bacano on the Cabrestero Block, La Belleza on Block VIM-1 and Capachos Block offset by negative revisions in Tigana on the LLA-34 Block.
(4) Reserve acquisitions are associated with the evaluations of the Arauca Block.

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.

The GLJ Report assumes that the proved undeveloped reserves will be developed over the next 5 years with 85% of the capital spending in the next 3 years. 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). See *Risk Factors* in the MD&A.

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, 2019, 2020 and 2021 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 Crude and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	—	2,921	18,265	57,799	12	2,582	—	30	18,267	61,180
2020	1,389	4,669	2,143	35,512	—	2,434	—	36	3,532	40,623
2021	4,542	12,197	19,658	21,756	1,894	4,593	223	303	24,739	35,022

The GLJ Report disclosed Company gross proved undeveloped reserves of 35,022 Mboe 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 undeveloped reserves in the GLJ Report estimates future capital spending of approximately $337.1 million to fully develop the undeveloped reserves and it is expected that these undeveloped reserves would be reclassified as proved developed reserves. Development of the undeveloped reserves is expected to occur over the next 5 years with over 100% of the investment expected over the next 4 years. Timing of the investment and the desired pace of development will depend to a large extent on economic conditions, in particular, the world price of oil. The Company has significant development opportunities in several large properties and the pace of development is controlled to meet corporate capital expenditure targets. See *Principal Properties*.

Probable Undeveloped Reserves

Year	Light Crude and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (Mboe)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2019	1,489	4,795	10,506	28,500	5	1,625	—	18	11,996	33,584
2020	3,458	8,561	210	26,101	18,579	20,234	—	11	6,765	38,045
2021	2,744	17,067	17,586	23,700	2,576	29,894	110	144	20,869	45,894

The GLJ Report disclosed Company gross probable undeveloped reserves of 45,894 Mboe before royalties. Probable reserves are less certain to be recovered than proved reserves. Development of the undeveloped reserves is expected to occur over the next 5 years with 80% of the investment expected over the next 4 years. Timing of the investment and the desired pace of development will depend to a large extent on economic conditions, in particular, the world price of oil. The Company has significant development opportunities in several large properties and the pace of development is controlled to meet corporate capital expenditure targets.

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

General

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 the date of this Annual Information Form, 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* in the MD&A.

Abandonment and Reclamation Costs

The following table sets forth abandonment and reclamation costs deducted in the estimation of the Company's future net revenue using forecast prices and costs as included in the GLJ report:

Year	Total Proved Abandonment Costs ($000's)	Total Proved plus Probable Abandonment Costs ($000's)	Total Proved plus Probable plus Possible Abandonment Costs ($000's)
2022	—	—	—
2023	—	—	—
2024	—	—	—
Thereafter	82,814	100,727	115,352
Total Undiscounted	82,814	100,727	115,352
Total Discounted @ 10%	22,398	20,373	18,015

As at December 31, 2021 Parex had 201 net wells for which it expects to incur abandonment and reclamation costs in the total proved plus probable category (216 net wells in the proved plus probable plus possible category). The GLJ Report deducted $100.7 million (undiscounted) and $20.4 million (10% discount) for abandonment costs of wells with proved and probable reserves ($115.4 million (undiscounted) and $18.0 million (10% discount) for abandonment costs of wells with proved and probable and possible reserves), in estimating the future net revenues disclosed in this Annual Information Form.

The future net revenues disclosed in this Annual Information Form based on the GLJ Report do contain an allowance for abandonment and reclamation costs for facilities, pipelines and wells without reserves.

For further information on Parex' abandonment and reclamation costs see *Decommissioning Liabilities* in this Annual Information Form.

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
2022	205,933	243,886
2023	89,852	140,173
2024	39,299	66,638
2025	241	65,862
2026	451	451
Thereafter	36,254	22,819
Total for all years undiscounted	372,030	539,829
Total for all years discounted at 10% per year	323,463	460,102

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 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, 2021. 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, 2021.

	Oil Wells				Natural Gas Wells				Other Wells(3)	
	Producing		Non-Producing		Producing		Non-Producing			
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Colombia	176	113.65	58	41.7	2	1.75	3	2.625	49	37.93

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, 21 gross (14.7 net) oil wells were capable of production and had reserves assigned to them.

Properties with No Attributed Reserves

The following table sets out Parex and its Subsidiaries' unproved properties as at December 31, 2021.

	Gross Acres	Net Acres
Colombia	2,323,941	1,570,504

In 2022, approximately 306,567 gross (157,619 net) acres are scheduled to expire. Development of the Company's properties with no attributed reserves are subject to current *Industry Conditions* and uncertainties as indicated under *Risk Factors* in the MD&A.

Forward Contracts

See Note 22 - "*Financial Instruments and Risk Management*" and Note 24 "*Commitments and Contingencies*, to the consolidated financial statements of the Company for the year ended December 31, 2021, which information 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 periodically reviews the results of all risk management activities on all outstanding positions.

The Company did not have any commodity forward contracts as at December 31, 2021.

The Company had the following foreign currency risk management contracts in place as at December 31, 2021:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
November 19, 2021 to April 19, 2022	COP	Costless Collar	$15,000,000	3,600-4,325
November 19, 2021 to June 21, 2022	COP	Costless Collar	$15,000,000	3,600-4,375

Tax Horizon

The GLJ Report forecasts cash taxes in Colombia to be incurred in 2022 and the Company incurred cash taxes in prior years.

Costs Incurred

The following table summarizes certain costs incurred by the Company for the year ended December 31, 2021:

	Property Acquisition Costs ($000's)			
Country	Proved Properties	Unproved Properties	Exploration Costs ($000's)	Development Costs ($000's)
Colombia	—	1,356	63,726	211,361
Total	—	1,356	63,726	211,361

Exploration and Development Activities (to be updated)

The following table sets forth the wells in which the Company participated during the year ended December 31, 2021.

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	2.00	1.25	—	—	32.00	21.65	3.00	3.00	37.00	25.90
Gas	—	—	—	—	—	—	—	—	—	—
Disposal	1.00	0.55	—	—	1.00	0.55	—	—	2.00	1.10
Untested	3.00	2.50	—	—	1.00	0.55	—	—	4.00	3.05
Suspended	1.00	0.50	—	—	—	—	—	—	1.00	0.50
Dry	5.00	3.05	—	—	—	—	—	—	5.00	3.05
Total	**12.00**	**7.85**	**—**	**—**	**34.00**	**22.75**	**3.00**	**3.00**	**49.00**	**33.60**

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, 2021, 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 $88.0 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 15 years. The present value of this amount is approximately $36.7 million discounted at 9.3%. The Company expects to incur approximately $5.7 million of these expenditures over the next financial year.

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, 2021, the estimated total inflated, undiscounted amount required to settle the environmental obligations was approximately $25.9 million. The present value of this amount is approximately $18.2 million discounted at 9.3%. The Company expects to incur $1.0 million of these expenditures over the next financial year.

Production Estimates

The following tables set out the volumes of gross and net production estimated for the year ending December 31, 2022, based on the GLJ Report for the year ended December 31, 2021; 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 - Disclosure of Reserves Data*.

	Light Crude and Medium Crude Oil (bbls/d)		Heavy Crude Oil (bbls/d)		Conventional Natural Gas (Mcf/d)		NGLs (bbl/d)		Oil Equivalent (boe/d)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved Producing	6,729	5,968	38,502	31,845	18,746	16,865	162	148	48,516	40,772
Developed Non-Producing	1,011	822	2,063	1,692	560	521	15	16	3,182	2,617
Undeveloped	4,797	4,172	3,129	2,504	(601)	(327)	119	110	7,945	6,732
Total Proved	12,536	10,963	43,694	36,040	18,704	17,060	295	275	59,643	50,121
Total Probable	1,862	1,640	1,755	1,413	(338)	(317)	9	8	3,570	3,009
Total Proved Plus Probable	14,399	12,603	45,449	37,453	18,367	16,743	304	283	63,213	53,130
Total Possible	1,850	1,555	1,259	1,023	42	36	5	4	3,122	2,587
Total Proved Plus Probable Plus Possible	16,249	14,158	46,708	38,476	18,408	16,779	309	288	66,335	55,718

Notes:

(1) Gross production is company working interest production before royalty deductions. Net production is company working interest production less royalties.

(2) Certain of the columns above may not add due to rounding of values.

The following tables set out the volumes of gross and net production estimated for the year ending December 31, 2022, based on the GLJ Report for the year ended December 31, 2021; for the Company's fields that account for 20% or more of the Company's total gross and net production.

Tigana, Colombia

	Light Crude Oil and Medium Crude Oil (bbls/d)		Heavy Crude Oil (bbls/d)		Conventional Natural Gas (Mcf/d)		Oil Equivalent (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	—	—	13,890	11,994	—	—	13,890	11,994
Developed Non-Producing	—	—	949	820	—	—	949	820
Undeveloped	—	—	884	702	—	—	884	702
Total Proved	—	—	15,723	13,515	—	—	15,723	13,515
Total Probable	—	—	723	599	—	—	723	599
Total Proved Plus Probable	—	—	16,446	14,114	—	—	16,446	14,114
Total Possible	—	—	444	369	—	—	444	369
Total Proved Plus Probable Plus Possible	—	—	16,890	14,484	—	—	16,890	14,484

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 2021				Year Ended 2021
	Dec. 31	Sept. 30	Jun. 30	Mar. 31	December
Average Daily Production(1)(3)					
Light Crude and Medium Crude Oil (Bbl/d)	6,376	6,955	5,881	8,131	6,831
Heavy Crude Oil (Bbl/d)	41,534	38,949	36,308	36,948	38,449
Conventional Natural Gas (Mcf/d)	11,214	9,552	10,266	10,200	10,308
Average Price Received (net of quality adjustment)(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	74.01	67.89	64.57	58.09	65.76
Heavy Crude Oil ($/Bbl)	68.51	63.08	60.08	52.52	61.37
Conventional Natural Gas ($/Mcf)	6.17	6.68	5.47	6.16	6.11
Royalties Paid(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	5.82	5.23	4.73	4.82	5.07
Heavy Crude Oil ($/Bbl)	13.00	11.04	9.43	4.39	10.19
Conventional Natural Gas ($/Mcf)	0.22	0.21	0.26	0.26	0.24
Production and Transportation Costs(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	16.26	12.29	13.59	15.53	15.87
Heavy Crude Oil ($/Bbl)	8.51	8.31	8.15	8.09	8.20
Conventional Natural Gas ($/Mcf)	1.13	2.08	1.80	1.52	1.01
Netback Received ($/BOE)(2)(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	51.93	50.37	46.25	37.74	44.82
Heavy Crude Oil ($/Bbl)	47.00	43.73	42.50	40.04	42.98
Conventional Natural Gas ($/Mcf)	4.82	4.39	3.41	4.38	4.86

Notes:

(1) Before deduction of royalties and after the Company's own consumption.

(2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues and is reported before any realized commodity price hedge gain or loss.

(3) The Company has not presented information for NGL production as it is immaterial (less than 1% of the Company's annual production for 2021).

(4) The Company's revenues, royalties and costs by product type are different from the Company's disclosed netback information contained in the Company's Management's Discussion and Analysis for the year ended December 31, 2021. Revenues, royalties and costs contained in the above table are approximations prepared by management for each product type. Netback information disclosed in the Management's Discussion and Analysis for the year ended December 31, 2021 blends heavy and light crude oil (rather than separating them by product type) and includes other adjustments on a Company consolidated basis.

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2021:

	Light Crude Oil and Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	BOE (BOE/d)
Tigana	—	14,803	—	14,803
Tua	—	1,652	—	1,652
Rumba	—	1,045	—	1,045
Jacana	—	13,470	—	13,470
Akira	2,215	—	—	2,215
Bacano	4,731	—	—	4,731
Capachos/Andina	4,085	—	1,569	4,347
Total	11,031	30,970	1,569	42,263

DIVIDEND POLICY

In 2021, the Board of Directors implemented a dividend program pursuant to which the Company expects to pay a regular quarterly cash dividend. If declared, the quarterly dividend is expected to be paid on or about the last day of the month in each quarter of March, June, September and December of each year to holders of record of Common Shares on or about the 15th day of such month.

It is intended that dividends declared and paid by Parex will qualify as "eligible dividends" for the purposes of the *Income Tax Act* (Canada) (and any similar applicable provincial legislation). No assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board of Directors.

Notwithstanding the foregoing, the decision to declare any dividend and the amount of future cash dividends declared and paid by Parex, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including, without limitation, business performance, operating environment where Parex' assets are located, financial condition, growth plans, fluctuations in commodity prices, production levels, expected capital expenditure requirements, operating costs, royalty burdens, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Parex or any of its Subsidiaries is a party from time to time (including, without limitation, the agreements governing the Credit Facilities), and the satisfaction of liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. The actual amount, the record date and the payment date of any dividend are subject to the discretion of the Board of Directors. There can be no assurance that dividends will be paid at the current rate or at any rate in the future.

The Board of Directors intends to review the dividend program from time to time, at its discretion. Depending on the foregoing factors and any other factors that the Board of Directors deems relevant from time to time, many of which are beyond the control of Parex, the Board of Directors may change the program following any such review or at any other time that the Board of Directors deems appropriate. Any such change may include, without restriction, future cash dividends being reduced or suspended entirely.

The Company did not pay any dividends in the years ended December 31, 2020 and 2019. During the year-ended December 31, 2021, the Company paid the following quarterly cash dividends:

($ per share Cdn)	Q1	Q2	Q3	Q4	Year
2021	$—	$—	$0.125	$0.375	$0.500

Included in the table above is a special cash dividend in the amount of Cdn$0.25 per Common Share declared on November 3, 2021 by the Board of Directors, which was paid on November 22, 2021 to holders of Common Shares of record as of November 16, 2021.

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 December 31, 2021, there were 120,265,664 Common Shares issued and outstanding and as at March 1, 2022, there were 118,028,284 Common shares issued and outstanding. The following is a description of the rights, privileges, restrictions 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 approved the adoption of a shareholder protection rights plan, which Parex Shareholder Rights Plan was approved by shareholders of PARI on October 30, 2009 and by Parex on May 23, 2012, was amended and restated and approved by shareholders of Parex on each May 12, 2015 and May 9, 2018, and the amended and restated version was reapproved by shareholders May 6, 2021 (the "**Parex Shareholder Rights Plan**"). 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 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 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.

BANK DEBT

As of the date hereof, Parex has a $200 million senior secured borrowing base credit facility with a syndicate of banks led by a major Canadian bank, consisting of a reserve-based revolving facility of $180 million and an operating line of $20 million (collectively the "**Credit Facilities**"). The Credit Facilities have a two year term, and may be extended by Parex after attaining syndicate approval provided the term of the Credit Facilities does not exceed two years. The facility is subject to re-determination of the borrowing base semi-annually on November 30 and May 31 of each year. 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. In the event that the syndicate reduces the borrowing base below the amount drawn at the time of redetermination, the Company has 180 days to eliminate any shortfall by providing additional security or guarantees satisfactory to the lenders or repaying amounts in excess of the new re-determined borrowing base. Advances under the revolving facility bear interest at rates ranging from US base rate or LIBOR plus 2.50% - 3.50% per annum, depending on utilization. Advances on the operating line bear interest at rates ranging from Canadian prime plus 1.50% - 2.50% per annum, dependent on utilization. Undrawn amounts under the Credit Facilities bear a commitment fee ranging from 0.5% to 0.7% per annum, dependent on utilization. Repayments of principal are not required provided that the borrowings under the Credit Facilities do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. Key covenants include a rolling four quarter total funded debt to adjusted 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 pledge of certain bank accounts and contracts. As at December 31, 2021 the utilization or draw on the Credit Facilities was nil.

In Colombia, the Company has provided guarantees to the ANH which on December 31, 2021 were $47.9 million to support the exploration work commitments on its blocks. The guarantees have been provided in the form of letters of credit for varying terms. EDC has provided performance security guarantees under the Company’s $150.0 million performance guarantee facility to support approximately $11.6 million of the letters of credit issued on behalf of Parex. The letters of credit issued to the ANH are reduced from time to time to reflect the work performed on the various blocks.

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
2022			
January	27.16	21.95	10,911,500
February	28.86	26.14	10,693,200
2021			
January	21.49	17.34	11,007,000
February	22.47	19.43	11,652,331
March	24.33	20.30	14,126,700
April	23.91	21.48	7,676,300
May	24.11	19.09	13,270,600
June	23.31	20.55	11,923,100
July	22.55	19.39	10,509,900
August	20.53	17.28	11,931,300
September	23.30	19.20	11,131,700
October	26.00	23.07	9,454,500
November	24.81	19.91	10,960,900
December	22.56	19.72	10,754,900

PRIOR SALES

During the year ended December 31, 2021, the Company granted an aggregate of 197,470 stock options to acquire an aggregate of 197,470 Common Shares with a weighted average exercise price of Cdn $21.68.

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. The information below is provided for the Company's directors and officers as at March 1, 2022.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer(4)	Principal Occupation (for last 5 years)
Lisa Colnett(3)(4)(5) Ontario, Canada	Director since May 12, 2015	Currently a Director and Chair of the Human Resources and Governance Committee of Parkland Corporation, an international supplier and marketer of fuel and petroleum products and a leading convenience store operator, and a Director of Northland Power, a global power producer. Ms. Colnett brings over 20 years of experience in human resources for a variety of industries ranging from mining to information technology. Since 1991, Ms. Colnett has held senior roles in human resources, information technology and strategy including Senior Vice President and Chief Information Officer of Celestica Inc., Senior Vice President, Human Resources, also of Celestica Inc. and Senior Vice President, Human Resources and Corporate Services, of Kinross Gold Corporation. Member of the Institute of Corporate Directors having completed the Directors Education Program.
Sigmund Cornelius(1)(4) Texas, United States	Director since May 14, 2020.	Mr. Cornelius serves as President of Freeport LNG Development L.P, a company based in Houston, Texas. From 1980 to 2010, he held various management and senior positions at ConocoPhillips Company, retiring as Chief Financial Officer in 2010.

Robert Engbloom, [2][5] Alberta, Canada	Director since September 29, 2009	Counsel, 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 40 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[5] Alberta, Canada	Director since August 28, 2009 and Chairman since May 11, 2017	Currently Chairman of the Board of Directors of Parex. Chief Executive Officer of Parex from September 29, 2009 to May 10, 2017. President of Parex from September 29, 2009 to November 5, 2015. President and Chief Executive Officer of PARI from 2004 to 2009. President and Chief Executive Officer of Dominion Energy Canada Ltd. from 1998 to October 2002, and then Consultant to March 2003.
Eric Furlan Alberta, Canada	Chief Operating Officer since February 5, 2018	Currently Chief Operating Officer of Parex, Senior Vice President of Engineering of Parex from 2017 to 2018 and Vice President of Engineering of the Company from 2012 to 2017. Mr. Furlan also served as the General Manager of Development at PARI. He has also held leadership and senior technical positions with Chevron Corporation both in Canada and internationally. Mr. Furlan is a professional engineer with close to 30 years of experience.
G. R. (Bob) MacDougall[1][3][5] Alberta, Canada	Director since October 4, 2016	Mr. MacDougall is a professional engineer with close to 30 years of domestic and international oil and gas operations and senior executive management experience. Mr. MacDougall was Executive Vice President and Chief Operation Officer of Vermilion Energy Corporation from 2004 to 2012. Member of the Institute of Corporate Directors having completed the Directors Education Program.
Glenn McNamara[2][3][5] Alberta, Canada	Director since October 4, 2016	Mr. McNamara is currently the President and Chief Executive Officer of Heritage Resources LP, a private fee title acreage owner business. Prior thereto, Mr. McNamara was the Chief Executive Officer and a director of PMI Resources Ltd. (formerly, Petromanas Energy Inc), a public oil and gas company from September 2010 to May 2016. From August 2005 to August 2010, Mr. McNamara was the President of BG Canada (part of the BG Group PLC, a public gas company with its head office in the United Kingdom, trading on the London Stock Exchange). Mr. McNamara also currently serves on the board of Whitecap Resources Inc. Member of the Institute of Corporate Directors having completed the Directors Education Program.
Imad Mohsen[5] Alberta, Canada	President and Chief Executive Officer since February 4, 2021.	Currently President and Chief Executive Officer of Parex. Mr. Mohsen is an engineering graduate of the Paris School of Mines (ENSMP). Sustainable Development Advisor then Private Advisor to the CEO at Royal Dutch Shell from 1997 to 2007. Development Manager, Subsea GOM from 2007 to 2011.General Manager, Operations for Shell Egypt JV (Bapetco) from 2011 to 2013. From 2013 until joining Parex, Mr. Mohsen joined Tulip Oil Holding B.V., a private equity backed upstream company founded in 2010 to explore for and develop oil and gas opportunities in Western Europe. After initially serving as COO, he was appointed CEO in 2015.
Kenneth Pinsky Alberta, Canada	Chief Financial Officer and Corporate Secretary since September 29, 2009	Currently Chief Financial Officer and Corporate Secretary of Parex since inception of the Company. Vice President Finance, Chief Financial Officer and Corporate Secretary of PARI from 2008 to 2009. 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. Mr. Pinsky is a Chartered Professional Accountant, CA and a Chartered Financial Analyst (CFA).
Carmen Sylvain[2][4][5] Alberta, Canada	Director since July 6, 2017	Currently has Board memberships with LCI International, Egyptian Refining Company, Orient Investment Properties Ltd. and the Canada Arab Business Council. Diplomat and public servant with 30 years of combined experience in foreign affairs, international trade and investment. Strategic Advisor to the OMERS Pension Fund from 2012 to 2014. Ms. Sylvain was Canada's Ambassador to Colombia from 2014 to 2016 and served in Global Affairs Canada as Assistant Deputy Minister for Strategic Planning and Policy where she led the development of the Foreign Policy Plan for Canada. Member of the Institute of Corporate Directors having completed the Directors Education Program.
Paul Wright[1][2][5] Alberta, Canada	Director since September 29, 2009	Currently works as a financial consultant. Mr. Wright is a Chartered Professional Accountant, CA with over 35 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 and Nominating Committee.

(3) Member of the Health, Safety and Environment and Reserves Committee.

(4) Member of the Human Resources and Compensation Committee.

(5) 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 1, 2022, the directors and officers of Parex, as a group, beneficially owned or controlled or directed, directly or indirectly, 2,434,652 Common Shares or approximately 2.06% 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

Mr. Cornelius was a director of Parallel Energy Trust (a TSX listed company) from March 2011 to February 2016. Parallel Energy Trust filed an application in the Court of Queen's Bench of Alberta for creditor protection under the Companies' Creditors Arrangement Act (Canada) and voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. In the Chapter 11 proceedings, the Bankruptcy Court approved the sale of the assets of Parallel Energy Trust and the sale closed on January 28, 2016. On March 3, 2016, the Canadian entities of Parallel Energy Trust filed for bankruptcy under the Bankruptcy and Insolvency Act (Canada) and a notice to creditors was sent by the trustee on March 4, 2016.

Mr. Cornelius was a director of United States Enrichment Corporation ("USEC") from March 2011 to 2014. In December 2013, USEC reached an agreement with its debt holders to file a prearranged and voluntary Chapter 11 bankruptcy restructuring in the first quarter of 2014. In March 2014, USEC filed the prearranged and voluntary Chapter 11 bankruptcy restructuring under Chapter 11 of the United States Bankruptcy Code. In September 2014, USEC emerged from bankruptcy proceedings with a new name, Centrus Energy Corp.

Mr. Cornelius was a director of CARBO Ceramics Inc. ("CARBO") from November 2009 to July 2020. In March 2020, CARBO and its direct wholly-owned subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas. As part of the process, CARBO entered into an agreement with Wilks Brothers, LLC. Pursuant to such agreement, CARBO emerged from Chapter 11 bankruptcy protection under new ownership of the Wilks Brothers, LLC.

No other current director or executive officer or security holder 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 other 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 executive 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* in the MD&A.

FINANCE AND AUDIT COMMITTEE INFORMATION

Finance and Audit Committee Mandate and Terms of Reference

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

Composition of the Finance and Audit Committee

The members of the Finance and Audit Committee are Paul Wright, Sigmund Cornelius and G.R. (Bob) MacDougall. All of 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. Mr. Wright is a Chartered Professional Accountant, CA with over 35 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.
Sigmund Cornelius Houston, Texas	Yes	Yes	Mr. Cornelius serves as President of Freeport LNG Development L.P, a company based in Houston, Texas. From 1980 to 2010, he held various management and senior positions at ConocoPhillips Company, retiring as Chief Financial Officer in 2010.
G. R. (Bob) MacDougall Calgary, Alberta	Yes	Yes	Mr. MacDougall is a professional engineer with close to 30 years of domestic and international oil and gas operations and senior executive management experience. Mr. MacDougall was Executive Vice President and Chief Operation Officer of Vermilion Energy Corporation from 2004 to 2012. Member of the Institute of Corporate Directors having completed the Directors Education Program.

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.

Nature of Services	Fees Paid to Auditor in the Year Ended December 31, 2021	Fees Paid to Auditor in the Year Ended December 31, 2020
Audit Fees(1)	$522,260	$629,337
Audit-Related Fees(2)	—	—
Tax Fees(3)	$273,482	$278,675
All Other Fees(4)	$540,378	$99,161
Total	$1,336,120	$1,007,173

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. In 2021 the Company engaged PricewaterhouseCoopers to assist with a one-time information system implementation. The fees for this specific project represent the majority of the non-audit, non-tax fees paid in 2021. In 2022, it is projected that Parex' non-audit fees will be reduced.

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada ("**Computershare**"). The Company's Common Shares are transferable at the offices of Computershare 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, as at December 31, 2021, there were no material legal proceedings to which the Company was a party or 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.

During the year ended December 31, 2021 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% 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:

- The Parex Shareholder Rights Plan. See *Description of Capital Structure*.
- 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* and *Bank Debt*.
- The Credit Facilities. 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 Professional 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 Professional 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. The industry related information in this section has been taken from public sources.

Colombia

Economic

GDP growth in Colombia was 10.6% in 2021 and Colombian inflation was 5.6% in 2021, 2.6% above the central bank's target rate of 3.0%. Based on the Central Bank of Colombia data, the Colombian peso was COP 3,743:$1 in 2021, compared to current rates of approximately COP 3,900.

For 2022 Colombian GDP is expected to grow by 5.5% in 2022 and 3.1% in 2023.

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 E&P Contracts are subject to this sliding scale royalty.

High Price Participation

For E&P Contracts signed under the new ANH oil regulatory regime, in 2004 and onwards, a high price share royalty applies once a production area or the contracted area (depending on the contract model) has cumulatively produced more than 5 MMbbls of oil, determined after the deduction of royalties. For the Company's ANH E&P Contracts, the high price share royalty 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) 2022 Threshold Prices**
Less than 10º API	Nil
10º to 15º API	$58.67/bbl
15º to 22º API	$41.07/bbl
22º to 29º API	$39.60/bbl
Greater than 29º API	$38.12/bbl

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

Crude oil production with a quality higher than 15º and lower than 22º API and a WTI oil price of $80/bbl results in a production share equivalent to an incremental 14% royalty, bringing the total government royalty to approximately 22% for a production area with production less than 5,000 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 other ANH E&P Contract holders and the ANH regarding the High Price Participation royalty.

X-Factor

For E&P Contracts acquired in the 2008 Heavy Oil Bid round and in some of the subsequent bid rounds, the ANH required an additional royalty percentage, or X-Factor, to be bid as the primary criteria for awarding of blocks by the ANH. The X-Factor is also now one of the bid criteria for new E&P Contracts, and the minimum X-Factor is one percent.

Summary of Fiscal Terms by ANH E&P Contract and Convenios

Each E&P Contract/Convenio 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 base royalty, high price participation factors and X-factors applicable to Parex' E&P Contracts/Convenios.

Block	Base Royalty	X-Factor	High Price Participation Basis
Aguas Blancas(2)	8%	—%	NIL
Arauca	32% base with 8% for incremental	—%	NIL
Boranda(2)	8%	—%	NIL
Cabrestero	8%	—%	Exploitation area + sliding scale factor
Capachos(2)	8%	—%	NIL
CPE-2-2	8%	1%	Block + sliding scale factor
CPO-4-1	8%	1%	Block + sliding scale factor
CPO-10	8%	1%	Block + sliding scale factor
CPO-11	8%	19%	Exploitation area + sliding scale factor
CPO-11-2	8%	1%	Block + sliding scale factor
De Mares(2)	8%	—%	NIL
Fortuna(1)	8%	—%	NIL
LLA-16-1	8%	1%	Block + sliding scale factor
LLA-26	8%	1%	Exploitation area + sliding scale factor
LLA-30	8%	1%	Exploitation area + sliding scale factor
LLA-32	8%	1%	Exploitation area + sliding scale factor
LLA-34	8%	1%	Exploitation area + sliding scale factor
LLA-38	8%	1%	Block + sliding scale factor
LLA-40	8%	1%	Block + sliding scale factor
LLA-43-1	8%	1%	Block + sliding scale factor
LLA-74	8%	1%	Block + sliding scale factor
LLA-81	8%	1%	Block + sliding scale factor
LLA-94	8%	1%	Block + sliding scale factor
LLA-95	8%	1%	Block + sliding scale factor
LLA-111	8%	1%	Block + sliding scale factor
LLA-112	8%	1%	Block + sliding scale factor
LLA-113	8%	1%	Block + sliding scale factor
LLA-122	8%	1%	Block + sliding scale factor
LLA-134	8%	1%	Block + sliding scale factor
Los Ocarros	8%	—%	Exploitation area + sliding scale factor
VIM-1	8%	17% (conventional) & 1% (unconventional)	Oil: Block + sliding scale factor Gas: 5 years after starting production + price conditions
VIM-10-2	8%	1%	Block + sliding scale factor
VIM-43	8%	1%	Block + sliding scale factor
VMM-4-2	8%	1%	Block + sliding scale factor
VMM-9	8%	1%	Block + sliding scale factor
VMM-46	8%	1%	Block + sliding scale factor
VSM-13-2	8%	1%	Block + sliding scale factor
VSM-25	8%	1%	Block + sliding scale factor
VSM-36	8%	1%	Block + sliding scale factor
VSM-37	8%	1%	Block + sliding scale factor
VSM-41-1	8%	1%	Block + sliding scale factor

Notes:

(1) There is an R Factor (additional royalty) applicable under the Association Contract with Ecopetrol if cumulative gross production exceeds 60 MMbbls.

(2) ANH Convenio

Income Tax

In the fourth quarter of 2019, the Colombian government enacted a new tax reform to replace the 2018 tax reform, which was overturned by the Colombian Constitutional Court. This new tax reform maintains the same corporate tax rates that were approved by the Colombian Congress in 2018. The enacted corporate tax rates are 32% for 2020, 31% for 2021 and 30% for 2022 and thereafter.

In the third quarter of 2021, the Colombian government enacted a new tax reform to replace the 2019 tax reform. The new tax reform increases the corporate tax rate to 35% from January 1, 2022 onwards.

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 ("E&P 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.

Also, the ANH developed a new contract for direct operated areas from Ecopetrol ("*Convenio*") with similar terms and conditions to the E&P Contract except for the non-application of economic rights and allowing the production period to last until the economic limit of the respective field.

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 two periods phases: (i) the exploration period, which lasts six years and comprises two phases (a) an initial phase 1 lasting 3 years and (b) an optional phase 2, which is also 3 years. Upon a declared discovery, and at the contractor's request, the evaluation stage commences and may last between one and five years (depending on the fulfillment of certain contractual conditions), during which the contractor must declare commerciality or relinquish the block; and (iii) the production period with a basic 24 year term, extendable under certain circumstances.

If a discovery is made, the contractor has the option to request an appraisal period of up to two years, with the possibility of extending such appraisal period in case of drilling exploration wells not included in the initial appraisal program. 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% for natural gas 10% for oil of the remaining reserves value.

Relinquishment of part or all the license area depends on which phase the operations are in. Except for 2019 E&P Contract where relinquishment of areas does not apply for the Exploration and Subsequent Exploration periods, under normal circumstances the contractor must relinquish 50% 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%. The operator and the ANH may also agree on the relinquishment of certain parts of a license 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.

In 2019 there were two bid rounds completed by the ANH and five new blocks were awarded to Parex Colombia. In 2020 there was one bid round completed by the ANH and two new blocks awarded to Parex Colombia. For the first time in recent history the ANH asked for industry to nominate blocks and where deemed appropriate, these blocks were included in the bid round.

In 2021 there was one bid round completed by the ANH and 18 blocks were awarded to Parex Colombia.

Environmental Regulation

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

1. Planning

The National Authority for Environmental Licenses ("**ANLA**") 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 ANLA awards an environmental license. The environmental license deals with usage of natural resources, road and site construction, flowlines, loading facilities and in general terms any activity orientated to exploration activities including production testing. Should exploration work result in a field to be declared commercial it requires a new development EIA and EMP for the development of a permanent oil and natural gas production field and development drilling. The process is similar to the one of the exploration phase.

An in-field pipeline (defined as wider than 6") design and construction is subject to a two part environmental licensing process. First, an environmental option assessment 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 license through a comprehensive EIA and EMP.

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

2. 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 complied with by the operator.

Crude 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. These include the 520-mile Ocensa pipeline, which has the capacity to transport 745,000 bbl/d from the Cusiana/Cupiagua area in the Llanos Basin. Additionally, the Cano Limon pipeline runs 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. The Bicentenario Pipeline is capable of transporting 110,000 bbls/d of crude oil from the Llanos Basin (Araguaney) to Banadia where it connects to the Cano Limon pipeline. Other transportation options exist besides pipelines to transport crude oil to export terminals such as truck and barge.

Colombia currently operates five refineries, four 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 domestic crude processing capacity is approximately 420,000 bbls/d.

RISK FACTORS

A discussion of risk factors can be found in the sections entitled *"Business Environment and Risks"* and "*Risk Factors"* in the MD&A, which sections are incorporated by reference into this AIF. The MD&A is available on the Company's SEDAR profile at www.sedar.com.

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

Report of Management and Directors on Reserves Data and Other Information

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.

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

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

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

DATED as of this 1st day of March , 2022.

(signed) "*Imad Mohsen*" Imad Mohsen President and Chief Executive Officer	(signed) "*Kenneth Pinsky*" Kenneth Pinsky Chief Financial Officer
(signed) "*Bob MacDougall*" Bob MacDougall Chairman of the HSE and Reserves Committee	(signed) "*Wayne Foo*" Wayne Foo Chairman of the Board of Directors

SCHEDULE "B"

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

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

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

1. We have evaluated the Company's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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.

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2021, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Ltd.	December 31, 2021	Colombia	—	4,881,317	—	4,881,317
Totals			—	4,881,317	—	4,881,317

6. 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.

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

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

EXECUTED as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, February 3, 2022

Original Signed by Patrick A. Olenick, P.Eng.
Vice President

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 (the "**Board**") 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 Finance & Audit Committee (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 reporting laws and regulations;
- any material disclosure of information to shareholders, securities regulators and the public, including, without limitation, the Corporation's annual information form; and
- if requested, significant acquisitions and divestitures.

The Audit Committee shall also take the steps necessary to address and resolve all instances or allegations of fraud or other complaints reported to the Audit Committee in accordance with the Corporation's Whistleblower Policy.

While the Audit Committee has the duties and responsibilities set forth herein, the Audit Committee is not responsible for planning or conducting an audit or for determining whether the Corporation’s financial statements are complete and accurate and are in accordance with generally accepted accounting principles or international financial reporting standards, as applicable. Similarly, it is not the responsibility of the Audit Committee to ensure that the Corporation complies with all laws and regulations.

As the Corporation is a reporting issuer under applicable securities laws the Board adopts the following Mandate for the Committee which reflects, among other things, compliance with stock exchange and legal requirements and guidelines for financial reporting.

2. Composition

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

(b) All members of the Audit Committee shall be Board members who are not members of management of the Corporation ("**Management**"). 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 amended ore replaced from time to time) of the Canadian Securities Administrators ("**NI 52-110**").

(c) 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.

(d) A member shall cease to be a member of the Audit Committee upon ceasing to be a director of the Corporation or upon ceasing to be "independent".

3. Meetings

(a) The Audit Committee shall meet at least quarterly with Management, and at least quarterly with the external auditors, such meetings generally coinciding with the release of interim or year-end financial information. Special meetings may be convened as required upon the request of the Audit Committee or the officers of the Corporation.

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

(c) 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.

(d) Minutes of each meeting shall be prepared.

(e) 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.

(f) The Audit Committee may invite the Chief Executive Officer or Chief Financial Officer or his or her 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 Chair 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, including any investigation in accordance with the Corporation's Whistleblower Policy.

(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**

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 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) press releases and all other public disclosure containing audited or unaudited financial information or financial guidance; and

(v) 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**

(i) Review annually and approve as required:

(A) 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;

(B) the adequacy and effectiveness of the Corporation’s accounting and internal control policies and procedures through inquiry and discussions with the Corporation's external auditors and Management;

(C) the quality and integrity of the Corporation's disclosure controls and procedures and management information systems through discussions with Management and the external auditors;

(D) major changes to the Corporation's disclosure controls and procedures and management information systems; and

(E) spending authority and approval of limits.

(ii) Oversee Management's reporting on internal controls and disclosure controls and procedures.

(c) **Enterprise Risk Management ("ERM")**

(i) Review and assess the identification and management of ERM matters pertaining to the Audit Committee.

(d) **External Auditors**

(i) instruct the auditors that: (a) they are ultimately accountable to the Audit Committee (as representatives of the shareholders of the Corporation); (b) they must report directly to the Committee; and (c) the Committee is responsible for the appointment (subject to shareholder approval), compensation, retention, evaluation and oversight of the Corporation's external auditors;

(ii) oversee the independence of the auditors and take such actions as it may deem necessary to satisfy it that the Corporation's auditors are independent within the meaning of applicable securities laws by, among other things: (a) requiring the independent auditors to deliver to the Audit Committee on a periodic basis a formal written statement delineating all relationships between the independent auditors and the Corporation; and (b) actively engaging in a dialogue with the independent auditors with respect to any disclosed relationships or services that may impact the objectivity and independence of the independent auditors and taking appropriate action to satisfy itself of the auditors' independence;

(iii) annually:

(A) recommend to the Board 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 the fees for the annual audit;

(C) review and recommend to the Board the compensation of the external auditors;

(D) assess the qualifications and performance of the auditors, taking into account the opinions of Management, and present conclusions to the Board;

(E) 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;

(F) ensure compliance with any legal requirements regarding the rotation of applicable partners of the external auditors, on a regular basis, as required;

(G) obtain a certificate attesting to the external auditors' independence, which identifies all relationships between the external auditors and the Corporation;

(H) review all reportable events, including disagreements, unresolved issues and consultations, as defined in National Instrument 51-102 – *Continuous Disclosure Obligations* (as amended or replaced from time to time) of the Canadian Securities Administrators ("**NI 51-102**"), on a routine basis, whether or not there is a change of auditors; and

(I) 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;

(iv) review the performance of the auditors and recommend to the Board the replacement or termination of the independent auditors (subject to required shareholder approvals) when circumstances warrant;

(v) 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;

(vi) generally oversee the work of the external auditor, including resolving any issues that arise between Management and the external auditors;

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

(viii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.

(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; and

(v) review and approve the Audit Committee information that may be required by applicable securities laws to be included in the Corporation's annual management proxy circular or annual information form, as applicable.

(f) **Legal**

(i) review annually the legal expenses incurred by the Corporation; and

(ii) assist the Board with oversight of the Corporation’s compliance with applicable legal and regulatory requirements, including meeting with general counsel and outside counsel, when appropriate, to review legal and regulatory matters, including any matters that may have a material impact on the financial statements of the Corporation.

(g) **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; and

(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.

(h) **New Business Development**

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.

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

Periodically, in conjunction with the Corporate Governance Committee:

(i) assess individual Audit Committee member and Chair performance and evaluate the performance of the Audit Committee as a whole, including its processes and effectiveness;

(ii) 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;

(iii) review the Corporation's procedures for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

(iv) take the steps necessary to address and resolve all instances or allegations of fraud or other complaints reported to the Audit Committee in accordance with the Corporation's Whistleblower Policy; and

(v) 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.

(j) **ESTMA**

Review and report to the Board on the procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**") at such time as Parex is required to comply with ESTMA.

(k) **Environmental, Social and Governance ("ESG")**

(i) In collaboration with the ESG Steering Committee (the "**ESG Committee**") review and assess ESG-related risks relevant to the Corporation, including those identified in the Corporation's annual ESG report.

(ii) Regularly review the Corporation's risk management policies, processes and analyses relative to addressing ESG risks.

(iii) Review the Corporation's annual ESG report and other ESG related disclosures in furtherance of executing on the Committee's duties and responsibilities set forth in this Mandate.

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, ethical issues or concerns raised under the Corporation's Whistleblower Policy.

(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. Finance and Audit Committee Evaluation

Annually in conjunction with the Corporate Governance and Nominating Committee:

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

(b) Develop and approve committee member eligibility criteria, identify directors qualified to become Committee members and recommend appointments to and removals from the Committee.

8. Mandate Review

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

9. Authorization

This Audit Committee Mandate is hereby approved on behalf of the Board this 30th day of October, 2009 as amended on November 9, 2011, November 13, 2013, November 2, 2015, October 4, 2017, March 5, 2018, and February 4, 2021.

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Paul Wright
Chairman of the Audit Committee
Parex Resources Inc.

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Wayne Foo
Chairman of the Board of Directors
Parex Resources Inc.