PAREX RESOURCES INC

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2022

MARCH 8, 2023

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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, 2022.

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 8, 2023, the closing buying rate for one U.S. dollar in Canadian dollars as certified by the Bank of Canada was 1.3785.

	Year Ended December 31		
	2022	**2021**	**2020**
Highest rate during the period	1.3856	1.2942	1.4496
Lowest rate during the period	1.2451	1.2040	1.2718
Average closing rate for the period	1.3013	1.2535	1.3415
Rate at the end of the period	1.3544	1.2678	1.2732

NON-GAAP AND OTHER FINANCIAL MEASURES ADVISORY

This Annual Information Form 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 IFRS and might not be comparable to similar financial measures disclosed by other issuers. Investors are cautioned that non-GAAP financial measures should not be construed as alternatives to or more meaningful than the most directly comparable GAAP measures as indicators of Parex' performance. 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 MD&A under the heading "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;

"**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;

"**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;

"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;

"Credit Facilities" has the meaning set forth under *Bank Debt* in this Annual Information Form;

"**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;

"GDP" means gross domestic product;

"**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 years ended December 31, 2022 and 2021 dated March 8, 2023;

"**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 Colombia**" means Parex Resources (Colombia) AG, a corporation organized under the laws of Barbados and redomiciled to Switzerland in June 2022;

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

"**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;

"**Verano Energy**" means Verano Energy (Switzerland) AG, a corporation organized under the laws of Barbados and redomiciled to Bermuda in September 2019 and then to Switzerland in June 2022; and

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, letter of credit costs to secure commitments 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 2, 2023 evaluating the oil and natural gas reserves of the Company as at December 31, 2022;

"**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:

- Parex' strategy, plans and focus;
- Parex' goal of becoming the largest independent energy producer in Colombia;
- Parex' growth strategy and the anticipated benefits to be derived therefrom;
- Parex' ambition to become a multi-field operator;
- Parex' expectations that it will pay a regular quarterly dividend and the anticipated timing and terms thereof;
- the anticipated termination date of the 2023 NCIB and the expectation that the Company will submit a notice of intention to make an NCIB application to the TSX for calendar 2024;
- the Company's forecast voluntary corporate restructuring benefits and the anticipated costs and timing thereof;
- 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;
- forecasted abandonment and reclamation costs and the anticipated timing thereof;
- Parex' expectations that there will not be any significant factors or uncertainties that would affect its properties with no attributed reserves and that the abandonment and reclamation costs associated with such properties will not be material;
- the timing of land that will be relinquished;
- the 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, the anticipated timing thereof and Parex' anticipated means of funding such costs;
- that Parex does not anticipate that interest or other funding costs would make further development of any of its properties uneconomic;
- 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 the Company's environmental obligations and the anticipated timing thereof;
- estimated volumes of gross and net production in 2023;
- anticipated growth in Colombia's GDP in 2023 and 2024;
- expectations that Parex' non-audit fees will be reduced in 2023;
- 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 and cost 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;
- the Company's risk management program; and
- the Company's oil and natural gas production levels

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, and Switzerland; 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, and Switzerland; 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 may 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; the risk that the Company may not become the largest independent energy producer in Colombia; the risk that the Company may not become a multi-field operator; the risk that the Company may not submit a notice of intention to make an NCIB to the TSX for calendar 2024; the risk that environmental protection requirements may have a significant financial or operational effect on Parex' capital expenditures, earnings or competitive position; the risk that costs in connection with abandonment and reclamation, asset retirement obligations and environmental obligations may be greater than anticipated; the risk that Parex' non-audit fees may not be reduced in 2023; the risk that interest or other funding costs would make the further development of any of Parex' properties uneconomic, the risk that Parex may not have sufficient financial resources in the future to pay a dividend or repurchase its Common Shares through an NCIB; the risk that the Board of Directors may not declare dividends in the future or that Parex' dividend policy changes; 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 provided by 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 pay dividends; 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.

The Company's future shareholder distributions, including but not limited to the payment of dividends and the acquisition by the Company of its Common Shares pursuant to its NCIB, if any, and the level thereof is uncertain. Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith and any special dividends) or acquire Common Shares of the Company will be subject to the discretion of the Board of Directors and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance that the Company will pay dividends or repurchase any Common Shares of the Company in the future. The payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely. In addition to the foregoing, the Company's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Company has incurred or may incur in the future, including the terms of the Credit Facilities.

MARKET, INDEPENDENT THIRD PARTY AND INDUSTRY DATA

Certain market, independent third party and industry data contained in this Annual Information Form is based upon information from government or other independent industry publications and reports or based on estimates derived from such publications and reports. Government and industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but none of Parex or its affiliates have conducted their own independent verification of such information. This Annual Information Form also includes certain data derived from independent third parties, including, but not limited to: the summary of certain information contained in *Industry Conditions* in this Annual Information Form. While Parex believes this data to be reliable, market and industry data is subject to variations and cannot be verified with complete certainty due to limits on the availability and reliability of raw data, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any statistical survey. None of Parex or its affiliates have independently verified any of the data from independent third-party sources referred to in this presentation or ascertained the underlying assumptions relied upon by such sources.

PAREX RESOURCES INC.

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.

Parex is the largest independent oil and gas company in Colombia, focusing on sustainable, conventional oil and gas production. Parex' corporate headquarters are in Calgary, Canada, and the Company has an operating office in Bogotá, Colombia. Parex is a member of the S&P/TSX Composite ESG Index and is a reporting issuer in each of the Provinces of Canada and its Common Shares trade on the TSX under the symbol "PXT".

Parex has a strong track-record of delivering total shareholder returns as well as long-term benefits to the community.

In support of the Company's growth strategy, Parex is leveraging industry-proven, but new-to-Colombia technology. As the largest independent land holder in Colombia, Parex is actively exploring and exploiting its high-quality asset portfolio with ambitions to grow the Company and become a multi-field operator.

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.

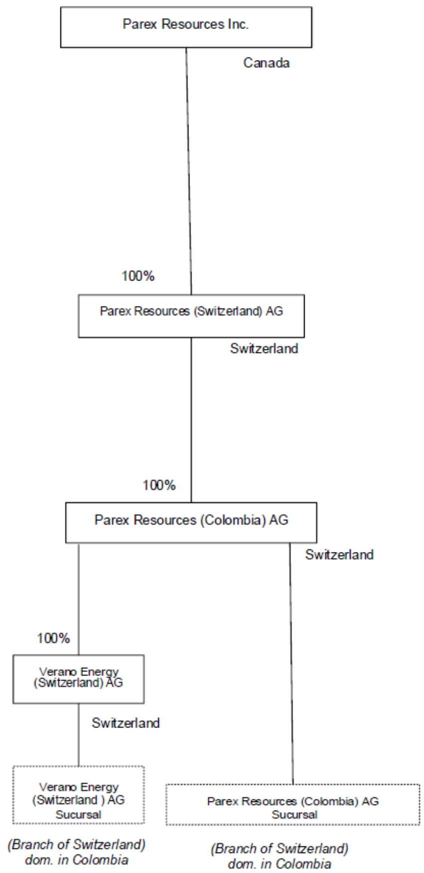
The following chart sets forth, as of the date hereof, the name of each Material Subsidiary, the jurisdiction of incorporation, continuance or organization, the registered holder of the voting shares of each Material Subsidiary, the percentage of voting shares held and the business conducted by each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

Name of Subsidiary	Jurisdiction of Incorporation, Continuance or Organization	Registered Holder of Voting Securities and Percentage Held	Business Conducted
Parex Resources (Switzerland) AG	Switzerland (art. 620 et seq. of the Swiss Code of Obligations ("CO"))	Parex (100%)	Holding company.
Parex Resources (Colombia) AG.	Switzerland (art. 620 et seq. of the CO)	Parex Resources (Switzerland) AG (100%)	The Company conducts certain activities in Colombia through a Colombian branch of this entity.
Verano Energy (Switzerland) AG	Switzerland (art. 620 et seq. of the "CO")	Parex Resources (Colombia) AG (100%)	The Company conducts certain activities in Colombia 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 Energy 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 and the Company conducts all of its activities in Colombia through these two branches.

All of the Company's Material Subsidiaries (which excludes its Colombian branches) are domiciled in countries where the legal system is based upon civil code. The Colombian branches are domiciled in Colombia, which also has a legal system based upon civil code. Switzerland has a banking system and advisory services (legal and accounting) that are comparable to North America. Switzerland has a tax treaty with Canada. Colombia has a free trade agreement and a tax convention with Canada and a bilateral investment treaty with Switzerland.

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.

Strategy

Parex continues to build on its track record of success as a responsible and sustainable Colombian oil and gas E&P company. Parex delivers value by applying its business fundamentals in each decision it makes by ensuring safe and sustainable production, progressing high-impact exploration opportunities, leveraging Parex' ESG performance and delivering strong return of capital.

Through strategic land acquisitions and joint venture agreements, Parex has grown its land holdings and portfolio potential exponentially since 2019. The Company's growth strategy has three pillars: (1) investing in technology to optimize capital efficiency and unlock Colombia's vast resource, (2) growing onshore gas production from liquids-rich gas fields, and (3) targeting transformational, high-impact exploration opportunities. By progressing each pillar, the Parex portfolio will continue to be the foundation for strong shareholder returns.

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 financial years ended December 31, 2020, 2021 and 2022. 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, 2020, 2021 and 2022, 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 Colombia* in this Annual Information Form.

Operational Activities

For a description of the Company's exploration, development and production activities in 2020, 2021 and 2022, 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, 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 (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);
- realized Brent referenced average realized sales price of $32.55/boe(1) and an operating netback of $20.84/boe(2);
- recognized net income of $99.3 million;
- generated funds flow provided by operations in 2020 of $297.0 million(3)($2.15 per share basic(2));
- incurred capital expenditures of $145.0 million(4); and
- participated in drilling 30 gross wells in Colombia resulting in 25 oil wells, 2 abandoned wells, 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 realized 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 provided by operations in 2021 of $577.5 million(3)($4.61 per share basic(2));
- implemented a regular quarterly dividend with aggregate dividends paid for the year of $47.6 million or Cdn$0.50 per Common Share(1);
- incurred capital expenditures of $272.2 million(4); and
- participated in drilling 49 gross wells in Colombia resulting in 34 oil wells, 1 abandoned well and 4 wells under test, for a success rate of 85%.

Year ended December 31, 2022

- achieved annual average oil and natural gas production in 2022 of 52,049 boe/d (consisting of 7,471 bbls/d of light crude oil and medium crude oil, 43,008 bbls/d of heavy crude oil and 9,420 Mcf/d of conventional natural gas), an increase of 11% over average 2021 production volumes of 46,998 boe/d;
- realized Brent referenced average realized sales price of $86.88/boe(1) and an operating netback of $59.06/boe(2);
- recognized net income of $611.4 million;
- generated funds flow provided by operations in 2022 of $724.9 million(3)($6.38 per share basic(2))';
- paid aggregate dividends for the year of $75.5 million or Cdn$0.89 per Common Share(1);
- incurred capital expenditures of $512.3 million(4); and
- participated in drilling 66 gross wells in Colombia resulting in 44 oil wells, 1 gas well, 7 abandoned wells, 8 wells under test and 6 pressure maintenance well, for a success rate of 87%.

(1) Supplementary Financial Measure (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory".
(2) Non-GAAP ratio (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory".
(3) Capital Management Measure (as defined in NI 52-112). See "Non-GAAP and Other Financial Measures Advisory".
(4) Non-GAAP Financial Measure(as defined in NI 52-112) . See "Non-GAAP and Other Financial Measures Advisory".

Normal Course Issuer Bid

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 Common 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 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 Common Shares under the NCIB and the NCIB formally terminated on January 3, 2023.

On January 4, 2023, the Company commenced an NCIB to purchase for cancellation, from time to time, as it considers advisable up to a maximum of 10,675,555 Common Shares on the open market through the facilities of the TSX and/or alternative trading systems. The NCIB will terminate on January 3, 2024 and Parex expects that it will, at the applicable time, submit a notice of intention to make an NCIB to the TSX for calendar 2024. 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. The Company has repurchased approximately $1.6 million shares to date in 2023 at an average price of Cdn$22.35 per share, for total consideration of Cdn$36 million under its current NCIB.

Voluntary Restructuring

In late 2022 Parex completed a voluntary, internal corporate entity restructuring that consolidated certain assets in the Southern Llanos basin into one corporate entity for operational and administrative optimization. The financial impact of this restructuring is that the Company will incur Colombia capital gains taxes in Q4 2022, while gaining an expected incremental increase of $325 million to the Company’s deferred tax asset balance as at year-end December 31, 2022, which is anticipated to provide benefits over the 2023-2027 fiscal year period. The restructuring had a cost, in the form of an increased current tax expense for Q4 2022, of $100 million. The Company’s Q4 2022 current tax expense was $163.1 million, compared to the Company’s original internal forecast of approximately $75 million. Additionally, the Company's full-year 2022 net income incrementally increased by approximately $225 million due to a deferred tax recovery, offset by the incremental Q4 2022 current tax expense of approximately $100 million.

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.

Set forth below is a description of the material exploration blocks located in Colombia that were acquired by the Company over the last three completed financial years:

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 was approximately $3.8 million to acquire 95 square kilometres of 3D seismic.

On July 7, 2021 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. Activities in the Arauca Block, Block LLA-38 and Capachos Block are currently suspended due to security concerns.

On December 22, 2021, Parex was awarded 18 prospective blocks **in the Colombia** bid round, being 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 and Blocks VSM-37, VSM-14-1 and VSM-13-2. The total work commitment on the newly awarded blocks was approximately $101.6 million. New E&P Contracts for all 18 blocks were executed on January 18, 2022.

PRINCIPAL PROPERTIES

As at December 31, 2022, 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	100%	118,769	118,769
Block LLA-16-1	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	100%	191,269	191,269
Block LLA-74	100%	148,263	148,263
Block LLA-81	100%	244,846	244,846
Block LLA-94	50%	89,175	44,588
Block LLA-95	100%	214,841	214,841
Block LLA-111	100%	600,226	600,226
Block LLA-112	100%	775	775
Block LLA-113	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	100%	732,703	732,703
CPO 4-1 Block	50%	14,826	7,413
CPO-10 Block	100%	735,141	735,141
CPO 11-2 Block[(3)]	50%	6,101	3,051
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	100%	335,017	335,017
Block VIM-43	100%	90,457	90,457
Block VMM-4-2	100%	102,288	102,288
Block VMM-9	100%	152,412	152,412
Block VSM-13-2	100%	228,450	228,450
Block VSM-14-1	100%	207,500	207,500
Block VSM-25	100%	68,221	68,221
Block VSM-36	100%	148,263	148,263
Block VSM-37	100%	119,543	119,543
Block VMM-46	100%	111,026	111,026
Boranda Block	50%	43,367	21,684
Fortuna Block[(4)]	100%	26,205	26,205
Total		5,857,628	5,467,354

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%).

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 summary of the Company's operational activities at its significant producing properties over the last three completed financial years is provided below.

Block LLA-34 (55% working interest)

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).

In 2022, Parex continued to delineate and develop the Tigana and Jacana pools and extend the Tigui and Tua oil fields, participating in the drilling of 28 wells resulting in 22 producing oil wells, 3 waterflood injection wells, 1 abandoned well and 2 wells under test. Average net oil production from Block LLA-34 in 2022 was 31,359 bbl/d net (consisting of 172 bbl/d light crude oil and medium crude oil and 31,187 bbl/d of heavy crude oil) or 57,016 boe/d gross (consisting of 313 bbl/d light crude oil and medium crude oil and 56,704 bbl/d of heavy crude oil).

Cabrestero Block (100% working interest)

In 2020, Parex drilled 6 wells on the Cabrestero Block; the Bacano Oeste-3, 4 wells and the Akira 19, 20, 21 and 22 wells resulting in 6 producing oil wells. Average net oil production from the Cabrestero Block in 2020 was 4,902 bbl/d net (4,902 bbl/d gross) consisting entirely of heavy crude oil.

In 2021, Parex drilled 13 wells on the Cabrestero Block; the Bacano 9 and 22 wells, the Bacano Oeste-6, 7, 9, 10, 11 and 13 wells, the Bacano Sur-1 and 2 wells, the Bacano Suroeste-1 well, the Totoro Oeste-1 well and Totoro Sur-1 well. All wells drilled were 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.

In 2022, Parex drilled 22 wells on the Cabrestero Block. All wells drilled were oil producing wells or water injection wells to allow a field waterflood pressure maintenance scheme. Also in 2022, the Company brought its first solar farm project online. Average net oil production from the Cabrestero Block in 2022 was 11,178 bbl/d net (11,178 bbl/d gross) consisting entirely of heavy crude oil.

Capachos Block (50% working interest)

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. Average net oil production from the Capachos Block in 2020 was 3,380 boe/d net (consisting of 3,274 bbl/d of light crude oil and medium crude oil and 638 Mcf/d of conventional natural gas) or 6,760 boe/d gross (consisting of 6,548 bbl/d light crude oil and medium crude oil and 1,276 Mcf/d of conventional natural gas).

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).

In 2022, Parex drilled the Capachos-3 and Capachos Sur-4 wells on the Capachos Block which are awaiting tie-in in 2023.

Average net oil production from the Capachos Block in 2022 was 3,277 boe/d net (consisting of 2,982 bbl/d of light crude oil and medium crude oil and 1,771 Mcf/d of conventional natural gas) or 6,554 boe/d gross (consisting of 5,964 bbl/d light crude oil and medium crude oil and 3,542 Mcf/d of conventional natural gas).

Block VIM-1 (50% working interest)

In 2020, Parex did not drill any wells on Block VIM-1. Average oil production from Block VIM-1 in 2022 was 71 boe/d net (142 boe/d gross) consisting entirely of light crude oil and medium crude oil.

In 2021 Parex, drilled two wells: the Planadas-1 well and Basilea-1 wells which were each temporarily abandoned. Gas facility construction also commenced in 2021. Average oil production from Block VIM-1 in 2022 was 237 boe/d net (consisting of 188 bbl/d of light crude oil and medium crude oil and 293 Mcf/d of conventional natural gas) or 474 boe/d gross (consisting of 376 bbl/d of light crude oil and medium crude oil and 586 Mcf/d of conventional natural gas).

In 2022, Parex drilled three wells: the La Belleza-2 development well and the Vaduz-1 and Planadas-1ST1 exploration wells, which were each subsequently abandoned. Gas facility work was also completed during the year. Average oil production from Block VIM-1 in 2022 was 1,007 boe/d net (consisting of 755 bbl/d of light crude oil and medium crude oil and 1,510 Mcf/d of conventional natural gas) or 2,014 boe/d gross (consisting of 1,510 bbl/d of light crude oil and medium crude oil and 3,020 Mcf/d of conventional natural gas).

Summary of Block Commitments as of March 8, 2023

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 Period	Current Period Expiry Date	Outstanding Gross Financial Commitment	Outstanding Net Financial Commitment	Current Commitment
Arauca**	Phase 1	Temporarily suspended	$ 83,534,000	$ 83,534,000	2 development wells + work program to be agreed with partner
Capachos	Farmout	Temporarily suspended	$ 38,140,000	$ 38,140,000	2 wells and workover
CPE-2-2*	Phase 1	September 20, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
CPO-4-1*	Phase 1	September 20, 2025	$ 5,844,736	$ 2,922,368	1 exploration well
CPO-10*	Phase 0	January 18, 2024	$ 5,844,736	$ 5,844,736	1 exploration well
CPO-11-2*	Phase 1	October 4, 2025	$ 5,844,736	$ 2,922,368	1 exploration well
Fortuna	N/A	N/A	$ 8,000,000	$ 8,000,000	1 exploration well
LLA-4-1*	Phase 0	January 18, 2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-16-1*	Phase 1	November 11, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-38	Phase 1	Suspended	$ 56,666,666	$ 56,666,666	Seismic + 1 exploration well
LLA-43-1*	Phase 0	January 18, 2024	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-74*	Phase 1	October 7, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-81*	Phase 1	August 26, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-94	Phase 1	October 1, 2023	$ 6,894,720	$ 3,447,360	1 exploration well
LLA-95*	Phase 1	August 26, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-111*	Phase 1	August 26, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-112*	Phase 1	September 16, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
LLA-113*	Phase 1	September 28, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
VIM-1	PEP Phase 1	January 30, 2025	$ 10,640,000	$ 5,320,000	1 exploration well
VIM-1	Evaluation	December 31, 2024	$ 600,000	$ 300,000	Feasibility studies
VIM-10-2*	Phase 1	September 27, 2025	$ 5,066,112	$ 5,066,112	1 exploration well
VIM-43*	Phase 1	July 30, 2024	$ 23,611,730	$ 23,611,730	1 exploration well
VMM-4-2*	Phase 1	September 20, 2025	$ 5,844,736	$ 5,844,736	1 exploration well
VMM-9	Phase 1	Suspended	$ 89,090,800	$ 89,090,800	Seismic + 5 exploration wells
VSM-13-2	Phase 0	January 18, 2024	$ 3,842,560	$ 3,842,560	1 exploration well
VSM-14-1	Phase 0	January 18, 2024	$ 3,842,560	$ 3,842,560	1 exploration well
VSM-25	Phase 0	Suspended	$ 19,832,960	$ 19,832,960	Seismic + 1 exploration well
VSM-36	Phase 0	June 21, 2023	$ 12,129,600	$ 12,129,600	Seismic
VSM-37*	Phase 1	August 19, 2025	$ 7,685,120	$ 7,685,120	2 exploration wells
TOTAL			$ 451,403,132	$ 436,491,036	

***Exploration well commitment can be drilled up to the end of the exploration period.**
****Farm-in commitment**

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 June 2022, Parex Resources (Barbados) Ltd., Parex Resources (Colombia) Ltd. and Verano Energy Limited, redomiciled to Switzerland and changed their names to Parex Resources (Switzerland) AG, Parex Resources (Colombia) AG and Verano Energy (Switzerland) AG, respectively. 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, 2020, 2021 and 2022:

	Number of Employees		
	2022	**2021**	**2020**
Canada (Calgary)	83	62	51
Colombia	345	309	297
Total	**428**	**371**	**348**

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 2023. 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 2022, 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, 2022, 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 2021 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.

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, 2022. The effective date of the Reserves Data is December 31, 2022 and the preparation date of the Reserves Data is January 25, 2023. 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 2, 2023 with an effective date of December 31, 2022. 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, 2022. 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 of Colombia. 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 ("HSE, Reserves Committee") of the Board of Directors has reviewed and approved the GLJ Report. The Board of Directors on the recommendation of the HSE, Reserves Committee, have also 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, 2022
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	9,105	8,171	70,320	59,080	18,983	17,943	199	195	82,788	70,436
Developed Non-Producing	6,593	5,717	4,149	3,450	4,180	3,908	328	322	11,767	10,140
Undeveloped	14,570	13,209	19,425	16,267	7,955	7,399	779	755	36,100	31,464
TOTAL PROVED	30,268	27,097	93,895	78,797	31,118	29,249	1,306	1,271	130,655	112,040
TOTAL PROBABLE	20,990	18,558	42,688	36,326	35,052	33,119	530	513	70,050	60,918
TOTAL PROVED PLUS PROBABLE	51,258	45,655	136,583	115,124	66,171	62,368	1,835	1,784	200,704	172,958
TOTAL POSSIBLE	27,899	24,624	43,397	36,907	54,506	51,247	510	495	80,891	70,567
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	79,157	70,279	179,980	152,031	120,676	113,615	2,345	2,279	281,595	243,525

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, 2022
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	3,533,633	2,977,950	2,579,916	2,283,629	2,055,709	2,558,051	2,148,377	1,855,066	1,637,116	1,469,870	36.63	6.10
Developed Non-Producing	497,806	411,347	349,156	302,894	267,448	281,698	231,232	194,710	167,478	146,608	34.43	5.74
Undeveloped	1,301,576	1,031,316	832,858	684,377	570,961	740,091	562,623	433,557	338,167	266,255	26.47	4.41
TOTAL PROVED	5,333,015	4,420,613	3,761,930	3,270,900	2,894,118	3,579,840	2,942,232	2,483,333	2,142,761	1,882,733	33.58	5.60
PROBABLE	3,287,795	2,304,639	1,719,251	1,345,143	1,091,440	1,870,312	1,294,105	952,221	734,604	587,640	28.22	4.70
TOTAL PROVED PLUS PROBABLE	8,620,809	6,725,251	5,481,181	4,616,043	3,985,558	5,450,153	4,236,337	3,435,554	2,877,365	2,470,373	31.69	5.28
POSSIBLE	4,037,941	2,594,490	1,832,846	1,384,416	1,096,702	2,277,244	1,454,939	1,020,025	763,904	599,729	25.97	4.33
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE	12,658,751	9,319,741	7,314,027	6,000,459	5,082,260	7,727,396	5,691,276	4,455,579	3,641,269	3,070,102	30.03	5.01

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 Colombian 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, 2022
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	8,599,772	1,340,310	1,331,551	491,597	103,300	5,333,015	1,753,174	3,579,840
PROVED PLUS PROBABLE	13,420,002	2,098,957	1,960,760	620,072	119,404	8,620,809	3,170,657	5,450,153
PROVED PLUS PROBABLE PLUS POSSIBLE	19,043,333	3,015,689	2,530,165	707,135	131,593	12,658,751	4,931,354	7,727,396

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, 2022.

(2) See *Significant Factors and Uncertainties - Abandonment and Reclamation Costs*.

FUTURE NET REVENUE
BY PRODUCT TYPE(5)
as at December 31, 2022
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)	988,767	40.10	6.68
Heavy Crude Oil(1)	2,750,033	45.92	7.65
Conventional Natural Gas(2)	23,130	41.82	6.97
Total Proved	3,761,930	44.21	7.37
Proved Plus Probable			
Light Crude Oil and Medium Crude Oil(1)	1,671,258	38.70	6.45
Heavy Crude Oil(1)	3,773,499	42.95	7.16
Conventional Natural Gas(2)	36,425	41.55	6.92
Total Proved Plus Probable	5,481,181	41.55	6.92
Proved Plus Probable Plus Possible			
Light Crude Oil and Medium Crude Oil(1)	2,545,793	37.06	6.18
Heavy Crude Oil(1)	4,715,926	40.54	6.76
Conventional Natural Gas(2)	52,308	40.75	6.79
Total Proved Plus Probable Plus Possible	7,314,027	39.26	6.54

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, 2022, 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, 2022
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)				
2023	75.00	80.00	—	0.735
2024	75.00	80.50	2.0	0.745
2025	75.43	81.50	2.0	0.755
2026	76.94	82.00	2.0	0.765
2027	78.48	82.53	2.0	0.775
2028	80.05	84.14	2.0	0.775
2029	81.65	85.85	2.0	0.775
2030	83.28	87.58	2.0	0.775
2031	84.95	89.32	2.0	0.775
2032	86.65	91.11	2.0	0.775
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, 2022.

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 $5.00 per MMBtu. Solution gas produced in the Aguas Blancas Field is to be sold under several individual contracts with varying commitment volumes and prices ranging from $2.12 per MMBtu to $3.80 per MMBtu. The average sales price for the initial 970 MBtu per day of production is $3.33 per MMBtu, with the excess production volumes above 970 MBtu per day being sold at $3.80 per MMBtu. Gas sale prices have been calculated annually by reserves category based on the production forecast. Solution gas produced from the Arauca Field is to be sold at the contract price of $2.00 per MMBtu. 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 price (less transportation and compression fees) of $4.25 per MMBtu in the producing reserves scenarios and changes from $4.25 per MMBtu in 2023 to $4.95 per MMBtu thereafter in the total proved, total proved plus probable and total proved plus probable plus possible scenarios producing reserves scenarios. In 2022 Parex realized an average price for natural gas sales of $6.07/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, 2022 against such reserves as at December 31, 2021 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, 2022
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, 2021	21,693	21,589	43,282	97,739	45,582	143,321
Discoveries[2]	949	247	1,196	275	150	425
Extensions and improved recovery[3]	4,359	310	4,669	7,279	2,432	9,711
Technical Revisions[4]	2,058	(3,246)	(1,188)	7,901	(3,259)	4,642
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	118	(66)	52	135	(62)	73
Production	(2,645)	—	(2,645)	(15,698)	—	(15,698)
December 31, 2022	26,532	18,834	45,366	97,630	44,844	142,474

	Conventional Natural Gas			BOE		
FACTORS	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2021	31,817	36,886	68,703	125,266	73,559	198,825
Discoveries[2]	117	85	202	1,253	422	1,676
Extensions and improved recovery[3]	1,202	(385)	817	11,983	2,631	14,614
Technical Revisions[4]	1,420	(1,529)	(109)	10,898	(6,435)	4,462
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	(4)	(4)	252	(128)	124
Production	(3,438)	—	(3,438)	(18,998)	—	(18,998)
December 31, 2022	31,118	35,052	66,171	130,655	70,050	200,704

Notes:
(1) The Company did not separately detail an NGL reserves reconciliation as the volumes were immaterial.
(2) Discoveries are associated with the evaluations of the LLA-40, Cabrestero and Capachos Blocks.
(3) Reserve extensions are associated with the evaluations of the Cabrestero, Arauca and Boranda Blocks. Improved recovery is associated with evaluations of the Cabrestero Block.
(4) Technical revisions are associated with the evaluation of additions on the LLA-34 and Capachos Blocks, offset by negative revisions on the Fortuna 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 7 years with 92% of the capital spending in the next 4 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, 2020, 2021 and 2022 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
2020	1,389	4,669	2,143	35,512	—	2,434	—	36	3,533	40,623
2021	4,542	12,197	19,658	21,756	1,894	4,593	223	303	24,739	35,022
2022	2,216	14,570	3,961	19,425	1,118	7,955	137	779	6,501	36,100

The GLJ Report disclosed Company gross proved undeveloped reserves of 36,100 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 $425.6 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 7 years with over 92% 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
2020	3,458	8,561	210	26,101	18,579	20,234	—	11	6,764	38,046
2021	2,744	17,067	17,586	23,700	2,576	29,894	110	144	20,869	45,894
2022	1,940	15,416	1,714	25,795	239	26,584	29	376	3,724	46,018

The GLJ Report disclosed Company gross probable undeveloped reserves of 46,018 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 and regulatory 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)
2023	—	—	—
2024	—	—	—
2025	—	—	—
Thereafter	103,300	119,404	131,593
Total Undiscounted	103,300	119,404	131,593
Total Discounted @ 10%	27,961	25,616	22,658

As at December 31, 2022 Parex had 242 net wells for which it expects to incur abandonment and reclamation costs in the total proved plus probable category (256 net wells in the proved plus probable plus possible category). The GLJ Report deducted $119.4 million (undiscounted) and $25.6 million (10% discount) for abandonment costs of wells with proved and probable reserves ($131.6 million (undiscounted) and $22.7 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
2023	296,797	335,557
2024	91,624	141,080
2025	48,564	87,647
2026	18,129	18,129
2027	1,215	1,068
Thereafter	35,268	36,591
Total for all years undiscounted	491,597	620,072
Total for all years discounted at 10% per year	433,388	544,087

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, 2022. 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, 2022.

	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	201	132.9	72	52.9	4	2.4	3	2.3	54	40.1

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

All of the Company's wells are located onshore. Of the non-producing wells, 29 gross (22.73 net) oil wells were capable of production and had reserves assigned to them. Wells are non-producing due to waiting on well servicing to replace bottom hole pumps.

Properties with No Attributed Reserves

The following table sets out Parex and its Subsidiaries' unproved properties as at December 31, 2022.

	Gross Acres	Net Acres
Colombia	5,812,425	5,437,893

In 2023, approximately 632,143 gross (399,932 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. See *"Summary of Block Commitments"* for commitment requirements.

Significant Factors or Uncertainties for Properties with No Attributed Reserves

Parex has capital allocated to the exploration of properties with no attributed reserves as part of its exploration program. See *"Summary of Block Commitments"* for commitment requirements. There are not expected to be any significant factors or uncertainties that would affect such properties at this time. The abandonment and reclamation costs associated with these properties are not expected to be material and will be included in the capital cost once incurred if temporarily plugged or abandoned upon further evaluation or non-economical results.

For information with respect to Parex' reclamation and abandonment obligations for its properties to which reserves have been attributed, see the section entitled *"Statement of Reserves Data and Other Oil and Gas Information - Abandonment and Reclamation Costs"* in this Annual Information Form.

Forward Contracts

See Note 23 - "*Financial Instruments and Risk Management*" and Note 25 "*Commitments and Contingencies*, to the consolidated financial statements of the Company for the year ended December 31, 2022, 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, 2022.

The Company had the following foreign currency risk management contracts in place as at December 31, 2022:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
September 2, 2022 to April 26, 2023	COP	Costless Collar	$15,000,000	4,000-5,000
September 2, 2022 to June 30, 2023	COP	Costless Collar	$15,000,000	4,000-5,100

The following is a summary of the foreign currency risk management contracts put in place since December 31, 2022:

Period Hedged	Reference	Currency Option Type	Amount USD	Strike Price COP
February 16, 2023 to June 15, 2023	COP	Costless Collar	$60,000,000	4,500-5,740

Tax Horizon

The GLJ Report forecasts cash taxes in Colombia to be incurred in 2023 and in future years 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, 2022:

	Property Acquisition Costs ($000's)			
Country	**Proved Properties**	**Unproved Properties**	**Exploration Costs ($000's)**	**Development Costs ($000's)**
Colombia	—	5,686	116,587	387,325
Total	—	5,686	116,587	387,325

Exploration and Development Activities

The following table sets forth the wells in which the Company participated during the year ended December 31, 2022.

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	5.00	4.05	—	—	39.00	28.55	6.00	4.65	50.00	37.25
Gas	1.00	0.50	—	—	—	—	—	—	1.00	0.50
Disposal	—	—	—	—	—	—	—	—	—	—
Untested	3.00	2.00	—	—	5.00	4.10	—	—	8.00	6.10
Suspended	—	—	—	—	—	—	—	—	—	—
Service wells	—	—	—	—	—	—	—	—	—	—
Stratigraphic test wells	—	—	—	—	—	—	—	—	—	—
Dry	6.00	4.50	—	—	1.00	0.55	—	—	7.00	5.05
Total	**15.00**	**11.05**	**—**	**—**	**45.00**	**33.20**	**6.00**	**4.65**	**66.00**	**48.90**

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, 2022, 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 $147.6 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 $38.8 million discounted at 14%. The Company expects to incur approximately $5.5 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, 2022, the estimated total inflated, undiscounted amount required to settle the environmental obligations was approximately $19.5 million. The present value of this amount is approximately $14.5 million discounted at 14%. The Company expects to incur $1.2 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 one year ending December 31, 2023, based on the GLJ Report for the year ended December 31, 2022; 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	9,034	8,157	37,454	31,060	8,486	7,981	209	205	48,112	40,752
Developed Non-Producing	3,425	3,022	1,467	1,174	2,069	1,925	185	182	5,422	4,698
Undeveloped	3,666	3,348	4,589	3,789	(998)	(984)	212	202	8,300	7,175
Total Proved	16,125	14,528	43,510	36,022	9,557	8,923	606	589	61,834	52,626
Total Probable	2,840	2,580	2,847	2,370	650	601	64	61	5,859	5,110
Total Proved Plus Probable	18,965	17,107	46,357	38,392	10,207	9,524	670	650	67,694	57,736
Total Possible	2,648	2,401	2,171	1,782	510	470	53	51	4,956	4,312
Total Proved Plus Probable Plus Possible	21,613	19,508	48,528	40,174	10,717	9,994	723	700	72,650	62,048

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, 2023, based on the GLJ Report for the year ended December 31, 2022; 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	—	—	11,014	9,663	—	—	11,014	9,663
Developed Non-Producing	—	—	46	40	—	—	46	40
Undeveloped	—	—	1,481	1,280	—	—	1,481	1,280
Total Proved	—	—	12,541	10,983	—	—	12,541	10,983
Total Probable	—	—	999	859	—	—	999	859
Total Proved Plus Probable	—	—	13,540	11,842	—	—	13,541	11,842
Total Possible	—	—	603	517	—	—	603	517
Total Proved Plus Probable Plus Possible	—	—	14,143	12,360	—	—	14,144	12,360

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 2022				Year Ended 2022
	Dec. 31	**Sept. 30**	**Jun. 30**	**Mar. 31**	**December**
Average Daily Production(1)(3)					
Light Crude and Medium Crude Oil (Bbl/d)	10,511	6,903	6,734	5,687	7,471
Heavy Crude Oil (Bbl/d)	42,746	43,063	42,373	43,865	43,008
Conventional Natural Gas (Mcf/d)	6,000	6,750	12,216	12,816	9,420
Average Price Received (net of quality adjustment)(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	80.19	94.76	105.72	94.80	91.97
Heavy Crude Oil ($/Bbl)	74.63	88.55	100.41	87.51	87.63
Conventional Natural Gas ($/Mcf)	5.79	6.00	6.09	6.23	6.07
Royalties Paid(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	7.32	8.50	10.44	8.15	8.42
Heavy Crude Oil ($/Bbl)	14.22	20.35	25.83	19.41	19.98
Conventional Natural Gas ($/Mcf)	0.19	0.20	0.19	0.22	0.20
Production and Transportation Costs(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	14.00	16.71	18.48	14.34	15.75
Heavy Crude Oil ($/Bbl)	9.73	9.92	8.41	8.04	9.02
Conventional Natural Gas ($/Mcf)	2.11	2.46	1.91	1.93	1.98
Netback Received ($/BOE)(2)(3)(4)					
Light Crude and Medium Crude Oil ($/Bbl)	58.87	69.55	76.80	72.31	67.80
Heavy Crude Oil ($/Bbl)	50.68	58.28	66.17	60.06	58.63
Conventional Natural Gas ($/Mcf)	3.49	3.34	3.99	4.08	3.89

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 2022).

(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, 2022. 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, 2022 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 the noted fields for the year ended December 31, 2022:

	Light Crude Oil and Medium Crude Oil (Bbls/d)	Heavy Crude Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	BOE (BOE/d)
Tigana	—	13,585	—	13,585
Tua	—	1,404	—	1,404
Rumba	—	766	—	766
Jacana	—	15,666	—	15,666
Akira	3,071	—	—	3,071
Bacano	8,107	—	—	8,107
Capachos/Andina	2,982	—	1,771	3,277
La Belleza	755	—	1,510	1,007
Total	14,915	31,421	3,281	46,883

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 year ended December 31, 2020. During the years ended December 31, 2022 and 2021, the Company paid the following quarterly cash dividends:

($ per share Cdn)	Q1	Q2	Q3	Q4	Year
2022	$0.140	$0.250	$0.250	$0.250	$0.89
2021	$—	$—	$0.125	$0.375	$0.50

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, 2022, there were 109,112,290 Common Shares issued and outstanding and as at March 8, 2023, there were 107,714,540 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 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 SOFR plus 1.65% - 3.25% per annum, depending on utilization. Advances on the operating line bear interest at rates ranging from Canadian prime plus 2.65% - 4.25% per annum, dependent on utilization. Undrawn amounts under the Credit Facilities bear a commitment fee ranging from 0.53% to 0.85% 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, 2022 the utilization or draw on the Credit Facilities was nil.

In Colombia, the Company has provided guarantees to the ANH which on December 31, 2022 were $129.1 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 $9.4 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**
2023			
January	23.37	19.26	10,828,600
February	24.61	21.96	13,229,200
2022			
January	27.16	21.95	10,911,500
February	28.86	26.14	10,693,200
March	30.44	24.74	15,673,400
April	27.11	23.78	12,152,800
May	28.98	23.11	11,485,000
June	30.16	20.60	17,166,700
July	23.88	19.29	8,749,000
August	24.07	18.85	15,359,400
September	21.96	18.20	12,080,200
October	22.78	20.18	9,933,800
November	23.49	18.83	13,381,700
December	20.36	17.81	13,230,100

PRIOR SALES

During the year ended December 31, 2022, the Company granted an aggregate of 172,103 stock options to acquire an aggregate of 172,103 Common Shares with a weighted average exercise price of Cdn $27.01.

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 8, 2023.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer[4]	Principal Occupation (for last 5 years)
Lynn Azar[1] The Hague, Netherlands	Director since July 13, 2022	Mrs. Azar is a senior finance executive who is currently Senior Vice President, Head of Finance at PlayStation Studios, a division of Sony Interactive Entertainment. Prior to this role, she spent 18 years in the energy industry at Shell, holding senior financial and commercial roles. Mrs. Azar has a Bachelors' and Masters' degree in Economics and Finance from the American University of Beirut, is a Certified Management Accountant (CMA) and a Chartered Financial Analyst (CFA) charterholder.
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 until 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 and Director 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 Education, Egyptian Refining Company and Orient Investment Properties Ltd.. 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. Member of the Institute of Corporate Directors having completed the Directors Education Program. Is a member of the Institute of Corporate Directors and The Qualified Risk Directors Insititutes having completed the Directors Education and the Qualified Risk Directors Programs.
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 8, 2023, the directors and officers of Parex, as a group, beneficially owned or controlled or directed, directly or indirectly, 2,454,438 Common Shares or approximately 2.28% 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 Sigmund Cornelius. Lynn Azar, G.R. (Bob) MacDougall and Paul Wright. 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
Sigmund Cornelius Houston, Texas (Chairman)	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.
Lynn Azar Den Haag, Netherlands	Yes	Yes	Mrs. Azar is a senior finance executive who is currently Senior Vice President, Head of Finance at PlayStation Studios, a division of Sony Interactive Entertainment. Prior to this role, she spent 18 years in the energy industry at Shell, holding senior financial and commercial roles. Mrs. Azar has a Bachelors' and Masters' degree in Economics and Finance from the American University of Beirut, is a Certified Management Accountant (CMA) and a Chartered Financial Analyst (CFA) charterholder.
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.
Paul Wright Calgary, Alberta	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.

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, 2022	Fees Paid to Auditor in the Year Ended December 31, 2021
Audit Fees(1)	$501,917	$522,260
Audit-Related Fees(2)	—	—
Tax Fees - Compliance(3)	$152,684	$185,579
Tax Fees - Consulting(3)	$166,373	$87,903
All Other Fees(4)	$424,583	$540,378
Total	$1,245,557	$1,336,120

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.

(3) "Tax Fees - Compliance" include fees related to tax compliance work for statutory tax obligations in the international jurisdictions that the Company operated in.

(4) "Tax Fees - Consulting" 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.

(5) "All Other Fees" include all other non-audit products and services. In 2021 the Company engaged PricewaterhouseCoopers to assist with a one-time human resource information system implementation. The fees for this specific project represent the majority of the non-audit, non-tax fees paid in 2021 and 2022. In 2023, 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, 2022, 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, 2022 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. See *Market, Independent Third Party and Industry Data* in this Annual Information Form.

Colombia

Economic

GDP growth in Colombia was 7.5% in 2022 and Colombian inflation was 13.1% in 2022, 10.1% above the central bank's target rate of 3.0%. Based on the Central Bank of Colombia data, the Colombian peso **("COP")** was 4,255:$1 in 2022, compared to current rates of approximately COP 4,877:$1.

Colombian GDP is expected to grow by 0.2% in 2023 and 1.7% in 2024.

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) 2023 Threshold Prices
Less than 10º API	Nil
10º to 15º API	$64.54/bbl
15º to 22º API	$45.18/bbl
22º to 29º API	$43.56/bbl
Greater than 29º API	$41.93/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[2]	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-11-2	8%	1%	Block + sliding scale factor
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-14-1	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

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 Convenios

Income Tax

In November 2022, the Colombian government enacted a new tax reform to replace a tax reform that was implemented in 2021. The new tax reform became effective January 1, 2023 and includes a base income tax rate for 2023 and beyond of 35% plus creation of a surtax between of 0% to 15% for Colombian oil companies. The surtax calculation is linked to the historical Brent oil price over a 10 year period. In addition, the reform also removes the previously allowed deduction of cash settled base royalties paid to the Colombian government from the income tax calculation.

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.

There were no Colombian federal bid rounds in 2022. Further, the Colombian government has stated that they intend to halt further bid rounds.

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 license normally includes obligations which have to be complied with by the operator.

Crude Oil 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, in 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 8th day of March , 2023.

(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, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, 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, 2022, 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, 2022	Colombia	—	5,481,181	—	5,481,181
Totals			—	5,481,181	—	5,481,181

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 2, 2023

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 this 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 Chair 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 or 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 the Corporation's 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, from time to time, to attend its meetings and take part in the discussion and consideration of matters being considered by 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.

(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.

(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.

(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.

(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 and Nominating 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 Environmental, Social and Governance Management Steering 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; and

(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

Parex' 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 the Committee 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, February 4, 2021 and August 3, 2022.

(signed) "Sigmund Cornelius"

Sigmund Cornelius
Chair of the Finance and Audit Committee
Parex Resources Inc.

(signed) "Wayne Foo"

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