RECONNAISSANCE ENERGY AFRICA LTD.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As of March 31, 2024

1. DATE OF STATEMENT

This statement of reserves data and other oil and gas information (the "**Statement**") of Reconnaissance Energy Africa Ltd. ("**ReconAfrica**" or the "**Company**") is dated July 29, 2024. The effective date of the information provided in this Statement is March 31, 2024 and the preparation date of the information provided in this Statement was April 1, 2024, unless otherwise indicated.

Cautionary Note Regarding Forward-Looking Statements

This Statement contains "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation in Canada, the United States and any other applicable jurisdiction (collectively, "**forward-looking statements**"). Forward-looking statements are provided as of the date of this Statement and the Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable securities laws.

Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Company, future production and grades, the economic limit or viability of assets, projections for sales growth, estimated revenues, resources, targets for cost savings, general economic conditions, the construction cost of new projects, the timing and outcome of exploration projects and drilling programs, projected capital expenditures, transportation costs, the timing of new projects, the outcome of legal proceedings, general public perception of the Company, the integration of acquisitions, future debt levels, fiscal regimes, the outlook for the prices of hydrocarbons, the outlook for economic recovery and trends in the trading environment, statements about strategies, cost synergies, revenue benefits or integration costs and production capacity of the Company and the industry and countries in which the Company operates. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties that may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Operating conditions can have a significant effect on the timing of events. Accordingly, investors are cautioned that events or circumstances could cause results to differ materially from those predicted. Management of the Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Statement should not be unduly relied upon.

In particular, this Statement contains forward-looking statements pertaining to, among others, the following:

- the Company's business strategy, strength and focus;
- expectations to add reserves through acquisitions and development of the Company's existing assets;
- the Company's aim to prove a potential reserve that could lead to economic stimulus, funding local and regional jobs and other socio-economic benefits such as increased infrastructure, potable water access and investments in environmental and wildlife conservation;
- expectations regarding the ongoing exploration process for the newly identified Kavango sedimentary basin in Northeast Namibia and Northwest Botswana (the "**Kavango Basin**"), including the Company's 2024 multi-well drilling campaign — the first of which is the Damara Fold Belt Prospect L (Naingopo) well (which the Company commenced drilling on July 7, 2024) and the second of which is the Damara Fold Belt Prospect P well (which is expected to spud immediately after completion of the Naingopo exploration well);
- expectations related to the work program at PEL 73 (as defined herein) following the Company's receipt of the Second Renewal Exploration Period covering the period January 30, 2024 to January 29, 2026;

- proven working conventional petroleum system with oil in stratigraphic wells and gas seeps in the Kavango Basin;
- expectations regarding the strategic joint venture transaction with BW Energy (as defined below) pursuant to the MOU (as defined below), including the timing and amount of cash payments relating to the joint venture transaction, the timing and amount of any bonus payments, the timing and amount of production milestone payments, and entering into a definitive agreement;
- expectations regarding the July 2024 Bought-Deal Financing (as defined below) including, the expected use of proceeds, the expected closing date, the completion of the July 2024 Bought-Deal Financing being subject to the receipt of all necessary regulatory approvals, including acceptance of the TSXV, any potential acceleration of the expiry date of the July 2024 Warrants (as defined below) and the listing of the Warrants (as defined below);
- expectations regarding future expenditures to be incurred or spent on the Company's assets;
- expectations regarding the Company's interpretation of data and models relating to its assets;
- operating results and future performance of the Company;
- information in respect of, or relating to, risked and un-risked prospective resources, including third party assessments and the Form 51-101F1 (as defined herein);
- the size, characteristics and features of the Company's oil and/or gas opportunities, future potential oil, natural gas and natural gas liquids, resources and the ability to commercially exploit them;
- the Company's proposed exploration, drilling and exploitation activities and timelines;
- expectations, given exploration success, regarding the future development of the Company's assets and the byproducts of such development;
- the potential returns for undiscovered oil and/or gas deposits in the Kavango Basin;
- ongoing activities by major industry competitors in Namibia and Botswana;
- the continuing competitiveness of the fiscal regimes in the jurisdictions in which the Company operates;
- the NAMCOR Transaction (as defined herein), being the Company's acquisition of half of the 10% carried participating interest in the Namibia Licence (as defined herein) held by NAMCOR (as defined herein);
- projections of market prices, including market prices for oil and natural gas, and costs;
- supply and demand for oil and natural gas;
- expectations regarding the infrastructure and transportation facilities that will be available to the Company for the storage and shipment of any products it may produce;
- the Company's intention in respect of maintaining sufficient insurance;
- updates of the Company's ongoing relationships with the Namibian and Botswanan governments and key ministries therein;
- expectations regarding the development of environmental laws and regulations, including as a result of the implementation of the Paris Agreement on climate change by various countries, the future costs to the Company associated with compliance with such laws and regulations and any potential changes to public perception following ongoing changes to climate laws;
- the Company's dividend policy; and
- expectations concerning any legal proceedings that the Company is a party to, including the potential settlement of the class action lawsuits filed by Company shareholders in the United States District Court in Brooklyn, New York and in the Supreme Court of British Columbia and the Company's intention to continue to vigorously defend the lawsuits.

Statements relating to "reserves" and "resources" (including prospective resources, as such terms are defined in the Form 51-101F1) are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future. See "*Oil and Gas Information*".

Forward-looking statements are based on the Company's current beliefs as well as assumptions made by, and information currently available to, the Company concerning future oil and natural gas production levels, future commodity prices, the ability to add oil and natural gas reserves through farm-in, acquisition and/or drilling at competitive prices, future exchange rates, the cost and availability of equipment and services in the field, the impact of increasing competition and the ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and discussed more extensively in the annual information form for the year ended March 31, 2024 under "*Risk Factors*":

- risks related to the nature of the business of the Company;
- exploration and production risks inherent in the oil and natural gas industry;
- risks related to permits, licences, approvals and authorizations;
- ongoing substantial capital requirements;
- weaknesses and volatility in the oil and gas industry;
- inflation;
- interest rates;
- negative operating cash flow;
- possible failure to realize anticipated benefits of acquisitions;
- commitments and contingencies;
- economic dependence;
- reliance on key individuals;
- marketability of crude oil and natural gas;
- project-related risks;
- climate change;
- risks of foreign operations;
- risks of operating through foreign subsidiaries;
- risks related to fraud, bribery and corruption in Namibia and Botswana;
- changes in government policy;
- royalty regimes;
- "resources" vs "reserves";
- estimates of resources;
- reserves estimates and reserve replacement risk;
- status and stage of development;
- availability of equipment and access restrictions;
- nature of reserves and additional funding requirements;
- third party credit risk;
- operating hazards and other uncertainties;
- competition;
- alternatives to and changing demand for petroleum products;
- global financial conditions;
- macro-economic risk;
- international conflicts;
- geo-political change;
- ongoing or future pandemics;
- sufficiency of insurance coverage;
- joint property ownership;
- joint venture risks;
- cyber attacks or terrorism;
- non-governmental organizations and eco-terrorism risks;
- infrastructure, energy and water supplies;
- disclosure controls and procedures;
- environmental regulations;

- market access constraints and oil and gas transportation risks;
- conflicts of interest;
- risks related to operating in African countries;
- tax regimes;
- foreign currency exchange risk;
- risks related to changes to national and local governmental laws and regulations;
- regulatory risks;
- management of growth;
- claims and legal proceedings;
- risks related to disclosure around Canada's *Extractive Sector Transparency Measures Act*;
- failure to comply with anti-bribery and anti-corruption laws;
- reputation risk;
- environmental, pollution, occupational health and safety risks;
- discretion regarding potential use of proceeds;
- volatility in the trading price of the Common Shares (as defined herein);
- liquidity of Common Shares and realization of investment in Common Shares;
- dilution and further sales of Common Shares; and
- dividends.

With respect to forward-looking statements contained in this Statement, ReconAfrica has also made assumptions regarding, among other things, the willingness of operators to conduct operations on certain properties in foreign jurisdictions; the future oil and/or gas prices or cost of products sold; the ability to obtain required capital to finance exploration, development and operations; the ability to maintain sufficient funds to continue the operations of the Company; the timely receipt of any required regulatory approvals; the ability to obtain drilling success consistent with expectations; the ability of the Company to secure adequate product transportation; no material variations in the current tax and regulatory environments; and the ability to obtain equipment, services, supplies and personnel in a timely manner to carry out its activities. Forward-looking statements and other information contained herein concerning the oil and/or gas industry and ReconAfrica's general expectations concerning this industry are based on estimates prepared by management of ReconAfrica with help from NSAI (as defined herein) and other third-party contractors using data from publicly available industry sources, as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of the industry. Although this data is generally indicative of relative market positions, market shares and performance characteristics, it is inherently imprecise. While ReconAfrica is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

The above summary of major risks and assumptions related to forward-looking statements included or incorporated by reference in this Statement has been provided for readers to gain a more complete perspective on the Company's future operations. However, readers should be cautioned that the above list of factors is not exhaustive and that this information may not be appropriate for other purposes. Forward-looking statements included or incorporated by reference in this Statement are valid only as at the date of this Statement, and the Company does not intend to update or revise these forward-looking statements except as required by applicable securities laws. The forward-looking statements contained in this Statement are expressly qualified by this cautionary statement.

Abbreviations

2U	best estimate scenario of prospective resources
acre-ft	acre-feet
bbl	barrels
Bcf	billions of cubic feet
BOE	barrels of oil equivalent
COGEH	Canadian Oil and Gas Evaluation Handbook
COGEH Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information included in the COGEH
km2	square kilometers
KS	Cretácico Superior
KM	Cretácico Medio
m	meters
Mbbl	thousands of barrels
Mcf	thousands of cubic feet
MD	measured depth
mD	millidarcies
MMbtu	millions of British thermal units
MMbbl	millions of barrels
MMcf	millions of cubic feet
NSAI	Netherland, Sewell & Associates, Inc.
OGIP	original gas-in-place
OOIP	original oil-in-place
P05	5 percent confidence level
P50	50 percent confidence level
P95	95 percent confidence level
P_d	chance of development
PEL	petroleum exploration licence
P_g	probability of geologic success
PHIE	effective porosity
rb/stb	reservoir barrels per stock tank barrel
scf/rcf	standard cubic feet per reservoir cubic foot
STARSS	Southern Trans-African rift and shear system
S_w	water saturation
SWE	effective water saturation
TVDSS	true vertical depth subsea
US$	United States dollars
USM$	thousands of United States dollars
USMM$	millions of United States dollars shale volume
VSP	vertical seismic profile

2. DISCLOSURE OF RESERVES DATA

The Company does not have any reserves (as such term is defined by National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**")).

On October 25, 2023, ReconAfrica disposed of its assets and operations in Mexico via the sale of Renaissance Oil Corp. ("**Renaissance**"), a wholly-owned subsidiary of the Company, which the Company did not consider to be material in the context of its business strategy, and therefore no longer has any reserves.

See the Appendix to this Statement for the Company's disclosure of the estimated prospective resources in certain prospects and leads located in the Damara Fold and Thrust Belt play area and the Karoo Rift play area of PEL 73 (as defined herein) in the Kavango Basin, northeastern Namibia.

3. PRICING ASSUMPTIONS

No pricing assumptions have been made due to the sale of all the Company's reserves as noted above.

4. RECONCILIATION OF CHANGES IN RESERVES

Reconciliation of Company Gross[(1)] Reserves by Product Type
As of March 31, 2024
Forecast Prices and Costs

	Light and Medium Crude Oil Combined[(2)]					Conventional Natural Gas					BOE				
Factors	Gross Proved (Mstb)	Gross Probable (Mstb)	Gross Proved Plus Probable (Mstb)	Gross Possible (Mstb)	Gross Proved Plus Probable Plus Possible (Mstb)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Possible (MMcf)	Gross Proved Plus Probable Plus Possible (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Possible (Mboe)	Gross Proved Plus Probable Plus Possible (Mboe)
March 31, 2023	**312.4**	**116.6**	**429.0**	**143.7**	**572.8**	**6,771.6**	**2,266.4**	**9,038.0**	**2,559.2**	**11,597.2**	**1,441.0**	**494.4**	**1,935.4**	**570.3**	**2,505.6**
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	(258.7)	(116.6)	(375.3)	(143.7)	(519.1)	(5,783.3)	(2,266.4)	(8,049.6)	(2,559.2)	(10,608.9)	(1,222.6)	(494.4)	(1,716.9)	(570.3)	(2,287.2)
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Production	(53.7)	0.0	(53.7)	0.0	(53.7)	(988.4)	0.0	(988.4)	0.0	(988.4)	(218.4)	0.0	(218.4)	0.0	(218.4)
March 31, 2024	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

(1) Company Gross Reserves means the Company's working interest reserves before calculation of royalties, and before consideration of the Company's royalty interests.

(2) Includes condensate reserves.

5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

As of March 31, 2024, the Company has no reserves.

6. OTHER OIL AND GAS INFORMATION

Properties with No Attributed Reserves

Namibia

Pursuant to the terms of a petroleum agreement among the Government of the Republic of Namibia, the National Petroleum Corporation of Namibia ("**NAMCOR**"), and Reconnaissance Energy Namibia Pty Ltd. ("**ReconNamibia**"), a wholly-owned subsidiary of ReconAfrica, dated January 26, 2015 and as adjusted on February 25, 2019 (the "**Petroleum Agreement**"), the Company holds a 90% interest (reduced to 70% in the event of closing of the Letter Agreement pursuant to its terms) in a petroleum exploration licence no. 0073 ("**PEL 73**") in respect of approximately 6.3 million acres (25,341.33 km^2) of oil and/or gas exploration properties comprising Blocks 1719, 1720, 1721, 1819, 1820 and 1821 situated in the Kavango Basin of northeast Namibia (the "**Namibia Licensed Property**"), granted by the Government of the Republic of Namibia to ReconNamibia and NAMCOR pursuant to the *Petroleum (Exploration and Production) Act, 1991* (Namibia) and governed by the Petroleum Agreement (the "**Namibia Licence**"). The Namibia Licence, which entitles ReconAfrica to apply for and receive, subject to Namibian government approval, a 25-year production licence upon successful discovery of an economically viable resource at the Namibia Licensed Property, and the Petroleum Agreement are ReconAfrica's main assets.

As of the date hereof, ReconAfrica owns a 90% interest in PEL 73, NAMCOR owns the remaining 10% interest in PEL 73 and ReconAfrica carries NAMCOR's costs through the development stage. On July 16, 2024, the Company entered into a memorandum of understanding ("MOU") for a strategic farm down of PEL 73 with BW Energy Limited ("BW Energy"), for a 20% working interest. In connection with the MOU, BW Energy agreed to a strategic equity investment in the Company for $22 million (US$16 million), pursuant to the July 2024 Offering. The Company is proposing to sell a 20% working interest in PEL 73 to BW Energy pursuant to the MOU in exchange for total potential consideration of US$141 million ($193 million), including a $22 million (US$16 million) equity investment. An additional US$45 million ($62 million) bonus will be earned at declaration of commerciality (Final Investment Decision or "FID") providing additional capital carry through to first production. These commerciality bonus payments will be paid in two installments, one at FID and the second payment one year after production. In the event of development of discoveries, production bonuses based on certain cash flow milestones achieved by BW Energy could total an additional US$80 million ($109 million). Three separate production bonus payments of US$25 million ($34 million), are made after BW Energy reaches certain free cash flow milestones. An additional first production payment of US$5 million ($7 million), is paid sixty days after the start of commercial production.

In Namibia, all rights in relation to the exploration for, the production and disposal of, and the control over petroleum vest in the state. The *Petroleum (Exploration and Production) Act 2 of 1991* (Namibia), together with the *Petroleum (Taxation) Act 3 of 1991* (Namibia) are the principal laws regulating the granting and transfer of petroleum licences to explore for and produce petroleum within the Republic of Namibia. Prior to a petroleum licence being granted, the *Petroleum (Exploration and Production) Act 2 of 1991* (Namibia) requires that the Namibian Minister of Mines and Energy enter into a petroleum agreement with the licence applicant containing the terms and conditions applicable to such licence and possible future licences, including production licences. On January 26, 2015, the Minister of Mines and Energy entered into the Petroleum Agreement with REN, now a wholly-owned subsidiary of ReconAfrica.

The following summary of key terms of the Petroleum Agreement is qualified in its entirety by the full text of the Petroleum Agreement, a copy of which is available on the Company's SEDAR+ profile at www.sedarplus.ca. Under the Petroleum Agreement, ReconAfrica was granted a 90% participation interest (reduced to 70% in the event of closing of the Letter Agreement pursuant to its terms) in the Namibia Licensed Property, with NAMCOR holding a 10% participation interest. The Petroleum Agreement describes an eight-year exploration work program and accompanying minimum expenditures on the Namibia Licensed Property related thereto. Such exploration program consists of the following three phases:

Initial Exploration Period (4 years, subject to possible one-year extension)

- Collection of existing surface and subsurface exploration data including, without limitation potential fields, remote sensing, satellite imagery, geomorphological, geochemical, radiometric and well data.
- Reprocessing and reinterpretation of all geological and geophysical data.
- Geochemical soil sampling and analysis.
- Initial integral assessment of the hydrocarbon potential of the area.
- Environmental impact assessment for both drilling and seismic acquisition activities.
- A minimum 500 kilometres of 2D seismic data for assessment of geology and basin structural configuration (with an option to replace the seismic program with two stratigraphic test wells to the base of the Karoo Super group sequences with total depth at the top of Damara belt related sequences).
- Full integral assessment of the hydrocarbon potential of the area and gross resources estimates.
- Planning for drilling two stratigraphic tests or exploration wells.

Minimum expenditures for the initial exploration phase, as prescribed by the Petroleum Agreement, total US$5,000,000. Additionally, the Company is required to spend US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration.

On October 22, 2018, the Namibia Ministry of Mines and Energy granted a one-year extension to the Initial Exploration Period of the Namibia Licence.

Pursuant to an adjustment letter dated February 25, 2019, the Namibia Ministry of Mines and Energy agreed to adjust the work commitment, minimum expenditure requirement, and timing of relinquishment under the Petroleum Agreement and the Namibia Licence such that the Company's work and expenditure commitments under the Initial Exploration Period will be deemed to have been satisfied provided that, by January 29, 2020, the Company drills one stratigraphic test well, rather than two. The drilling of one stratigraphic test well will fulfil the Company's work and expenditure obligation to the end of the Initial Exploration Period.

Pursuant to such adjustment letter, ReconAfrica's obligation to drill the second stratigraphic test well has been deferred to and becomes a part of the work commitments that must be satisfied during the First Renewal Exploration Period. Further, the relinquishment obligation which arises at the end of the Initial Exploration Period has been deferred into the First Renewal Exploration Period.

On December 18, 2019, Namibia's Minister of Mines and Energy confirmed that the Namibia Licence had been approved for its First Renewal Exploration Period, and accordingly the exploration phase of the Namibia Licence was renewed and continued until January 25, 2022. Such approval included recognition that the proposed work program for the First Renewal Exploration Period included the drilling of two stratigraphic test wells.

First Renewal Exploration Period (2 Years, subject to possible one-year extension)

- Acquire 250 kilometres of 2D seismic data.
- Drill and evaluate two stratigraphic and/or exploration wells.
- Design and plan 3D seismic acquisition program for continued exploration and drilling program.

Minimum expenditures for the First Renewal Exploration Period, as prescribed by the Petroleum Agreement, total US$10,000,000 plus an additional US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration. The work requirements for 2D seismic, well drilling and aggregate expenditure have been satisfied.

On September 10, 2021, Namibia's Minister of Mines and Energy granted approval of a one-year extension on the First Renewal Exploration Period, extending such period to January 29, 2023 due to the impacts of the COVID-19 pandemic on the Company's operations.

On September 5, 2022, Namibia's Minister of Mines and Energy granted approval of a further one-year extension on the First Renewal Exploration Period, extending such period to January 29, 2024.

On September 22, 2022, the Company announced that it had entered into a definitive purchase and sale agreement with NAMCOR dated September 21, 2022, to acquire half of NAMCOR's 10% carried participating interest in PEL 73 (the "**NAMCOR Transaction**"). The NAMCOR Transaction has not yet been completed as previously anticipated and discussions are ongoing between the Company and NAMCOR. The Company has agreed to issue 5,000,000 Common Shares to NAMCOR, subject to certain contractual restrictions on transfer, and pay US$2 million in cash for the acquisition of half of NAMCOR's 10% carried participating interest in the Namibia Licence. Completion of the NAMCOR Transaction is expected to follow fulfilment of various conditions precedent, including approval of the Ministry of Mines and Energy of Namibia, the approval or waiver of Namibia's competition authority and the acceptance by the TSXV. There can be no assurance that the NAMCOR Transaction will be completed on these terms or at all.

On October 30, 2023, Namibia's Minister of Mines and Energy confirmed that the Namibia Licence had been approved for its Second Renewal Exploration Period covering the period from January 30, 2024 to January 29, 2026, under revised terms as detailed in the following section.

Second Renewal Exploration Period (2 Years, subject to possible one-year extension)

- Either
  - acquire 500 kilometres of 2D seismic data, or
  - acquire 1,200 square kilometres of eFTG data, or
  - some combination of (i) or (ii) which is reasonable and achieves a significant increase in the data acquired by the Company during the Second Renewal Exploration Period.
- Design an exploration or stratigraphic test well and then drill such well.

Minimum expenditures for the Second Renewal Exploration Period, as prescribed by the Petroleum Agreement, total US$10,000,000 plus an additional US$50,000 per year (benchmarked to inflation) for the purposes of funding the education and training of Namibians, of which US$35,000 is to be paid to the Namibian Petroleum Training and Educational Fund and US$15,000 is to be paid in connection with the in-house training of Namibian citizens in the field of oil and/or gas exploration. However, as the Company's exploration expenditures in the First Renewal Exploration Period exceeded the minimum US$10,000,000, this excess of over US$60,000,000 may be applied to reduce the minimum exploration expenditure commitment in the Second Renewal Exploration Period. This treatment has been confirmed by the Namibia Ministry of Mines and Energy and accordingly there is no minimum exploration expenditure for the Second Renewal Exploration Period. This does not alter the Company's obligation to conduct the seismic and drilling exploration work described above, which remains outstanding.

Other Material Provisions

The Company is required to pay to the Government of Namibia an annual licensing fee ranging from NAD$60 to NAD$150 per square kilometre of the Namibia Licensed Property, depending on the applicable stage of exploration. Should the Namibian Minister of Mines and Energy grant a production licence over any part of the Namibia Licensed Property (as further described below), the annual licensing fee will increase to NAD$1,500 per square kilometre to which such production licence relates.

In accordance with the Petroleum Agreement, as adjusted by the February 25, 2019 and October 4, 2021 adjustment letters, the Company must relinquish at least 50% of the exploration area covered by the Namibia Licence at the end of the First Renewal Exploration Period (January 29, 2024). In determining the relinquished area, any areas of the Namibia Licensed Property that have been identified as potentially productive are excluded from the relinquishment requirements.

As part of the approval for the Second Renewal Exploration Period by the Namibian Ministry of Mines and Energy, the Company requested and on November 27, 2023 was granted, a relinquishment exemption based on the provisions of Section 37 (5) of the Petroleum Act of 1991. The request was based on the Company's belief following the evaluation of acquired subsurface data over the past three years that a significant portion of the PEL 73 will be prospective for the exploration of oil and gas. As a result, the Company does not have to relinquish any of the acreage and retains access to the entire Namibia Licence.

In the event the exploration work at the Namibia Licensed Property leads to the discovery of an economically viable petroleum reservoir, the Company may, pursuant to the terms of the Petroleum Agreement, make an application for a production licence. Within six months after making such application, subject to the provisions of the *Petroleum Act* (Namibia), the Namibian Minister of Mines and Energy may grant to the Company a 25-year production licence. The Company is required to pay, to the benefit of the Government of Namibia on a quarterly basis, a 5% production royalty based on the market value, as determined in accordance with the provisions of the Petroleum Agreement, of any natural gas or crude oil produced under a production licence granted pursuant to the Petroleum Agreement. An incremental three-tiered Additional Profits Tax ("**APT**") is charged on the after-tax net cash flow from petroleum operations in the Namibia Licensed Property. Exploration, development and operating expenditures, as well as royalty and corporate income tax, are all fully deductible in the year they are paid in the computation of the APT net cash flow for the year. APT will only be paid if the petroleum operations in the Namibia Licensed Property earn an after-tax real (i.e. inflation-adjusted) rate of return of 15%. The second and third tiers of APT become payable once the profitability level exceeds 20% and 25% respectively. The first-tier rate of APT is established in the legislation (through a formula) at 25%. The incremental second and third tier APT rates are determined in the Petroleum Agreement, and in the case of the Company, are 28% and 29%, respectively.

A copy of the Petroleum Agreement is available on SEDAR+ under ReconAfrica's profile at www.sedarplus.ca. See "*Material Contracts*".

Botswana

On June 9, 2020, the Company, through its wholly-owned subsidiary, Reconnaissance Energy Botswana (Pty) Ltd. ("ReconBotswana"), was granted a petroleum licence in northwestern Botswana (the "Botswana Licence") for approximately 2.45 million acres (9,921 km2) (later reduced to approximately 2.22 million acres or 8,900 km2 by amendment dated December 24, 2020 and further reduced to approximately 1.88 million acres (7,592 km2) by amendment dated April 13, 2023) (the "Botswana Licensed Property"). The lands subject to the Botswana Licence are contiguous to the Namibia Licensed Property. On June 9, 2020, the Company, through ReconBotswana, was granted the Botswana Licence. The terms of the Botswana Licence are as follows:

- 100% working interest in all petroleum rights from surface to basement;
- an initial 4-year exploration period, with renewals up to an additional 10 years, in accordance with the *Botswana Petroleum (Exploration and Production) Act*;
- upon declaration of commercial production, the operator holds the right to enter into a 25-year production licence with a 20-year renewal period, in accordance with the *Botswana Petroleum (Exploration and Production) Act*;
- royalties associated with the production licence will be subject to negotiation, in accordance with the *Botswana Petroleum (Exploration and Production) Act*, and generally range from 3 to 10% of gross revenue from production;
- the Company has committed to a minimum work program of 5,000,000 Botswana Pula (BWP) (approximately $500,000) over the first 4-year exploration period; and
- the corporate tax rate of Botswana is 22%.

The Company is at an early stage and in the process of completing desktop studies. ReconAfrica has completed a hydrogeology including groundwater feasibility study prepared by a Botswana third-party service company. The Botswana Licensed Property excludes National Parks, the Tsodilo Hills, RAMSAR area, and the Okavango Delta. The Company also self-imposes additional buffer zones to avoid environmentally sensitive areas.

In March 2024, the Company applied for a six-month extension of the Botswana Licence while it continued to negotiate a petroleum agreement with the government of Botswana. The Company has also applied for a renewal of the licence should the extension not be approved. Under the terms of the Botswana Petroleum Act the Botswana Licence is deemed to continue in force until the Minister makes a determination on the licence extension and renewal.

The fiscal regimes of both Namibia and Botswana are both globally competitive. In the "African Investment Index" published in 2018 by Quantum Global Research Lab, the independent research arm of the Quantum Global Group, a group of companies operating in the areas of investment management, private equity, active management and research with a focus on Africa, Quantum Global Research Lab ranked Botswana as the fourth most attractive investment destination in Africa.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

For information on significant factors or uncertainties relevant to properties with no attributed reserves, please refer to the Company's consolidated financial statements for the year ended March 31, 2024 and related management's discussion and analysis as available on the Company's profile on SEDAR+ at www.sedarplus.ca.

Forward Contracts

Currently there are no material forward contracts or commitments.

Tax Horizon

The Company's Namibia and Botswana projects are in the exploration and evaluation stage of development and capitalized costs to date will be available for deduction for income tax purposes. The Company does not expect to be taxable in the foreseeable future.

Costs Incurred

For information on exploration and development costs please refer to Note 6 of the Company's consolidated financial statements for the year ended March 31, 2024 and related management's discussion and analysis as available on the Company's profile on SEDAR+ at www.sedarplus.ca.

Exploration and Development Activities

Seismic Operations and Technical Studies

The Company conducted seismic operations in three phases (phase 1, phase 2 and the phase 2 extension) over three years, from 2021 to 2023. The operations were conducted using low impact methods: small footprint sources, state of the art wireless receiver technologies, cloud computing, and sensitivity and awareness in all operational activities. A total of 2,767 kilometres of seismic have been acquired over these three years, comprising 497 kilometres in Phase 1, 761 kilometres in Phase 2 and 1,509 kilometres in the Phase 2 Extension. The seismic data acquisition program has been completed and processed, providing a good regional 2D seismic data set over the most prospective areas of PEL 73.

Over the duration of the seismic operations, the Company, the seismic contractor (Polaris Natural Resources Ltd.), and its subcontractors employed over 630,000 man-hours and drove over two million kilometres without any significant health, safety, or environmental incidents; there were no lost time incidents in the two years of operations - Polaris first commenced work in Namibia in July 2021. Our two entities have worked hand-in-hand to achieve our exploration goals in 2D seismic data acquisition and to impact the local communities positively through employment, acquisition of services and procurement of goods in the Kavango East and Kavango West regions.

The first two phases identified a number of leads and considerably expanded the Company's portfolio of opportunities. The phase 2 extension was designed to better define these leads, de-risk potential drilling targets, and add new leads. The program was also designed to confirm the lateral extension of the Karoo Rift Basin to the south-east, potentially to the edge of PEL 73, and to delineate a new play fairway identified in Phase 1, the Damara Fold Belt.

The Company has further progressed its technical assessment of the Damara Fold Belt with the integration of new studies, basin modelling and all available geochemical data. The Company now anticipates potentially having oil in the shallower Mulden reservoir intervals, while the deeper Otavi target is expected to have natural gas with liquid/oil potential. Due to the coarse seismic grid over the Rift basin, the Company is evaluating options to acquire a 3D program to further delineate the identified leads prior to any drilling in the Rift. Seismic acquisition is anticipated to occur in the second half of 2025.

Enhanced Full Tensor Gravity ("eFTG") Survey

ReconAfrica engaged an airborne geophysical survey provider, Metatek Group Limited, to conduct an eFTG survey over an area of 2,184 square kilometres (540,000 acres) over the Company's exploration licence in Northeastern Namibia. This program was subsequently extended by 2,814 km2 (695,000 acres) in two contiguous areas, and the complete program is nearly 5,000 square kilometres. The data was acquired in April and May 2023.

The eFTG is an advanced three-component high resolution airborne gravity survey which specifically allows earth scientists to identify changes in sub-surface rock density with the goal of delineating hydrocarbon traps. Unlike traditional gravity instruments, which measures vertical responses, the eFTG (gravimetry) measures changes in the gravity response using multi-component airborne instruments. Simultaneously, high resolution magnetic and light detection and ranging ("LiDAR") data is also acquired, to correct and supplement the gravimetric data. When calibrated with existing 2D seismic data, the eFTG imaging can greatly enhance the geoscientists' ability to identify structures and extrapolate their geometries in three dimensions.

The processing and inversion of this data was completed and integrated with the seismic data to evaluate the Company's exploration inventory. This information, combined with the 2D seismic and well data, has enhanced the Company's ability to image and understand the sub-surface, significantly contributing to building a risk weighted prospect portfolio and defining the Company's future drilling program.

Drilling Program

The Company's initial drilling program, which commenced at the beginning of 2021, was designed to test organic rich source rocks, evidence of migrated hydrocarbons and conventional traps. ReconAfrica completed two wells in the third quarter of 2021 which achieved the stated purpose of the initial drilling program, the establishment of a working conventional petroleum system in the Kavango Basin. Well 1819/8-2 ("8-2"), located in the Kavango East region, 6.5 kilometres west of Kawe 6-2, began drilling on June 25, 2022 and finished at total depth on August 15, 2022. The well encountered hydrocarbon shows with gas (Methane) and gas liquids. Hydrocarbon shows with gases were identified between 838m and 1,807m, and between 1,990m and 2,058m; although geologically a successful well, economic accumulations of hydrocarbons were not encountered. The apparent lack of structural closure and potential oil source-maturation issues at this location highlighted the need for multiple seismic line confirmation and eFTG to support all new drilling decisions. The data gathered from the well program, seismic operations and the eFTG has led to the identification of a new play, the Damara Fold Belt.

The ReconAfrica technical team anticipates drilling multiple wells in the Damara Fold Belt, with drilling underway on the first well, Naingopo (Prospect L), which spud on July 7, 2024. The well is expected to drill to a depth of approximately 3,800 metres or 12,500 feet targeting both oil and natural gas. Drilling is expected to take approximately 90 days and will include three sets of logging operations, coring and reservoir testing. Following the drilling of the Naingopo well, the Company is planning to drill a second Damara Fold Belt well, Prospect P. Drilling of the second Damara Fold Belt well is expected to commence in the fourth quarter of 2024, subject to the results of the Naingopo well.

Production Estimates

The Company does not have any production estimates.

Production History

On May 10, 2016, Renaissance recorded first revenue from oil and gas operations after executing license contracts for the Mundo Nuevo, Topén and Malva blocks, located in Chiapas, Mexico. ReconAfrica acquired Renaissance on July 27, 2021, at which point it recorded first revenue from oil and gas operations.

The following table sets forth the Company's production volumes for the year ended March 31, 2024, by product type, for the fields comprising more than ten percent of the Company's total production:

	Year ended March 31, 2024		
	Oil (Bbl/d)	**Natural Gas (Mcf/d)**	**Total (Boe/d)**
Mundo Nuevo	168	3,715	787
Malva	55	352	114
	223	4,067	901

The following table sets forth the Company's average gross daily production volumes, for Mexico, the prices received, royalties paid, production costs incurred and the resulting netback on a per unit volume basis, for each quarter of the year ended March 31, 2024.

Average Production by Product	**Three Months Ended December 31, 2023**	**Three Months Ended September 30, 2023**	**Three Months Ended June 30, 2023**
Crude oil (Bbl/d)	170	185	285
Natural gas (Mcf/d)	3,703	3,836	4,464
Total (Boe/d)	787	825	1,029

Revenue From Product Sales		**Three Months Ended December 31, 2023**		**Three Months Ended September 30, 2023**		**Three Months Ended June 30, 2023**
Crude oil	$	746,871	$	1,718,198	$	2,258,889
Natural gas		1,024,431		1,952,742		1,911,080
Prior period adjustments		(26,795)		(18,919)		35,859
Total	$	1,744,507	$	3,652,021	$	4,205,828

Average Prices	**Three Months Ended December 31, 2023**	**Three Months Ended September 30, 2023**	**Three Months Ended June 30, 2023**
Crude oil ($/bbl)	107.03	100.76	87.05
Natural gas ($/mcf)	6.75	5.53	4.70

Royalties		**Three Months Ended December 31, 2023**		**Three Months Ended September 30, 2023**		**Three Months Ended June 30, 2023**
Charge for the period	$	1,529,723	$	3,132,851	$	3,383,666
Percentage of revenue		87.7%		85.8%		80.5%
Per Boe	$	47.38	$	41.29	$	36.13

Production Costs		**Three Months Ended December 31, 2023**		**Three Months Ended September 30, 2023**		**Three Months Ended June 30, 2023**
Charge for the period	$	297,297	$	401,377	$	270,449
Percentage of revenue		17.0%		11.0%		6.4%
Per Boe	$	9.21	$	5.29	$	2.89

Operating Netback		**Three Months Ended December 31, 2023**		**Three Months Ended September 30, 2023**		**Three Months Ended June 30, 2023**
Revenue From Product Sales	$	1,744,507	$	3,652,021	$	4,205,828
Royalties		(1,529,723)		(3,132,851)		(3,383,666)
Production costs		(297,297)		(401,377)		(270,449)
Operating Netback		(82,513)		117,793		551,713
Per Boe	$	(2.56)	$	1.55	$	5.89

*Figures in the tables above reflect production values for the period from April 1, 2023, until November 10, 2023, the date on which Renaissance was sold.

APPENDIX

OPTIONAL DISCLOSURE OF PROSPECTIVE RESOURCES DATA

ReconAfrica engaged Netherland, Sewell & Associates, Inc. ("**NSAI**"), an independent qualified reserves evaluator, to provide an updated prospective resource report dated June 26, 2024 (with an effective date of March 31, 2024) relating to the Company's prospective resources (previously defined as the "**Updated Report**"). The Updated Report focused solely the Company's interest in certain prospects and leads located in the Damara Fold and Thrust Belt (Damara) play area and the Karoo Rift play area of PEL 73 in the Kavango Basin, northeastern Namibia. The preparation date of the Updated Report is April 1, 2024; NSAI did not consider any geological, engineering, or financial data for its evaluation after that date.

The Updated Report was prepared using in accordance with the definitions and guidelines set forth in the *Canadian Oil & Gas Evaluation Handbook* prepared jointly by the Society of Petroleum and Engineers (Calgary Chapter) and in accordance with NI 51-101.

As of March 31, 2024 and the date hereof, ReconAfrica owns a 90 percent interest in PEL 73. The Namibian state oil company, NAMCOR, owns the remaining 10 percent interest in PEL 73 and ReconAfrica carries NAMCOR's costs through the development stage.

Subsequent to the year ended March 31, 2024, ReconAfrica signed a letter agreement with BW Energy Limited ("**BW Energy**") for a strategic farm down of PEL 73, for a 20% working interest. On completion of the transaction, the ownership interests in PEL 73 will be: ReconAfrica 70%, BW Energy 20%, and NAMCOR 10%. ReconAfrica will remain the operator of PEL 73.

Summary of Prospective Oil and Gas Resources

The Company has not yet established reserves on any of its properties in Namibia or Botswana due to the fact that its oil and/or gas activities are currently in the preliminary stages. The following information on the Namibia Licensed Property is derived from the Updated Report.

Exploration opportunities are subclassified as prospects or leads depending upon the available data and degree of interpretation. A prospect is considered to have enough data and interpretation such that it is currently ready to drill. A lead has insufficient data or interpretation to adequately identify a drillable structural closure and/or petroleum system at the current time. As of the date of this report, 25 prospects and 49 leads were identified and evaluated.

Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by applying future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further categorized according to the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. The prospective resources included in Updated Report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects and leads, as discussed in subsequent paragraphs. The Updated Report does not include economic analysis for these prospects and leads. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in the Updated Report have a reasonable chance of being economically viable. There is no certainty that any portion of the prospective resources will be discovered. If they are discovered, there is no certainty that it will be commercially viable to develop and produce any portion of the prospective resources.

Totals of unrisked prospective resources beyond the lead level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect and lead, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Summary of Best Estimate (2U) Prospective Light & Medium Crude Oil Resources
As of March 31, 2024 (MMbbl)

Play Area/Subclass	Unrisked			Risked[1]		
	Gross (100%)	Company Gross	Net[2]	Gross (100%)	Company Gross	Net[2]
Damara						
Prospects	3,423.6	3,081.2	2,927.2	225.6	203.0	192.9
Leads	153.1	137.8	130.9	5.5	5.0	4.7
Karoo Rift						
Prospects	484.5	436.1	414.3	25.2	22.7	21.6
Leads	1.602.5	1,442.3	1,370.2	37.8	34.0	32.3
Total PEL 73						
Prospects	3,908.1	3,517.3	3,341.4	250.8	225.7	214.4
Leads	1,755.6	1,580.1	1,501.1	43.4	39.0	37.1

Notes:

1. These estimates are based on unrisked prospective resources that have been risked for chance of discovery and chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.
2. Net prospective resources are after a 5-percent deduction for royalties.
3. Prospective resources are the arithmetic sum of multiple probability distributions.
4. Totals may not add because of rounding.

Oil volumes in the tables above are expressed in millions of barrels (MMbbl); a barrel is equivalent to 42 United States gallons.

The prospective resources shown in the Updated Report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. Low estimate and high estimate prospective resources have not been included in the Updated Report.

For the purposes of the Updated Report, the volumes and parameters associated with the best estimate scenario of prospective resources are referred to as 2U. The 2U prospective resources have been aggregated beyond the prospect and lead level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation. Statistical principles indicate that the arithmetic sums of multiple estimates may be misleading as to the volumes that may actually be recovered.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. The prospective resources included in the Updated Report represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made; prospective resources have both an associated chance of discovery (P_g) and a chance of development (P_d), which together define the chance of commerciality.

Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation.

Development risking addresses the probability of development given geologic success; this risk analysis is conducted based on the associated economic and development related factors (development plan, production forecasts, markets, facilities, capital and operating costs, product prices, approvals, etc.). For the purposes of this assessment of development risk, NSAI has considered the primary elements to be (1) financial considerations, (2) access to sales markets, (3) development plan approval, and (4) government and regulatory approvals.

Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in the Updated Report is a discussion of the primary geologic risk elements for each prospect and lead.

Each prospect and lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect or lead drilling outcomes. If petroleum discoveries are made, smaller-volume prospects and leads may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in the Updated Report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects and leads.

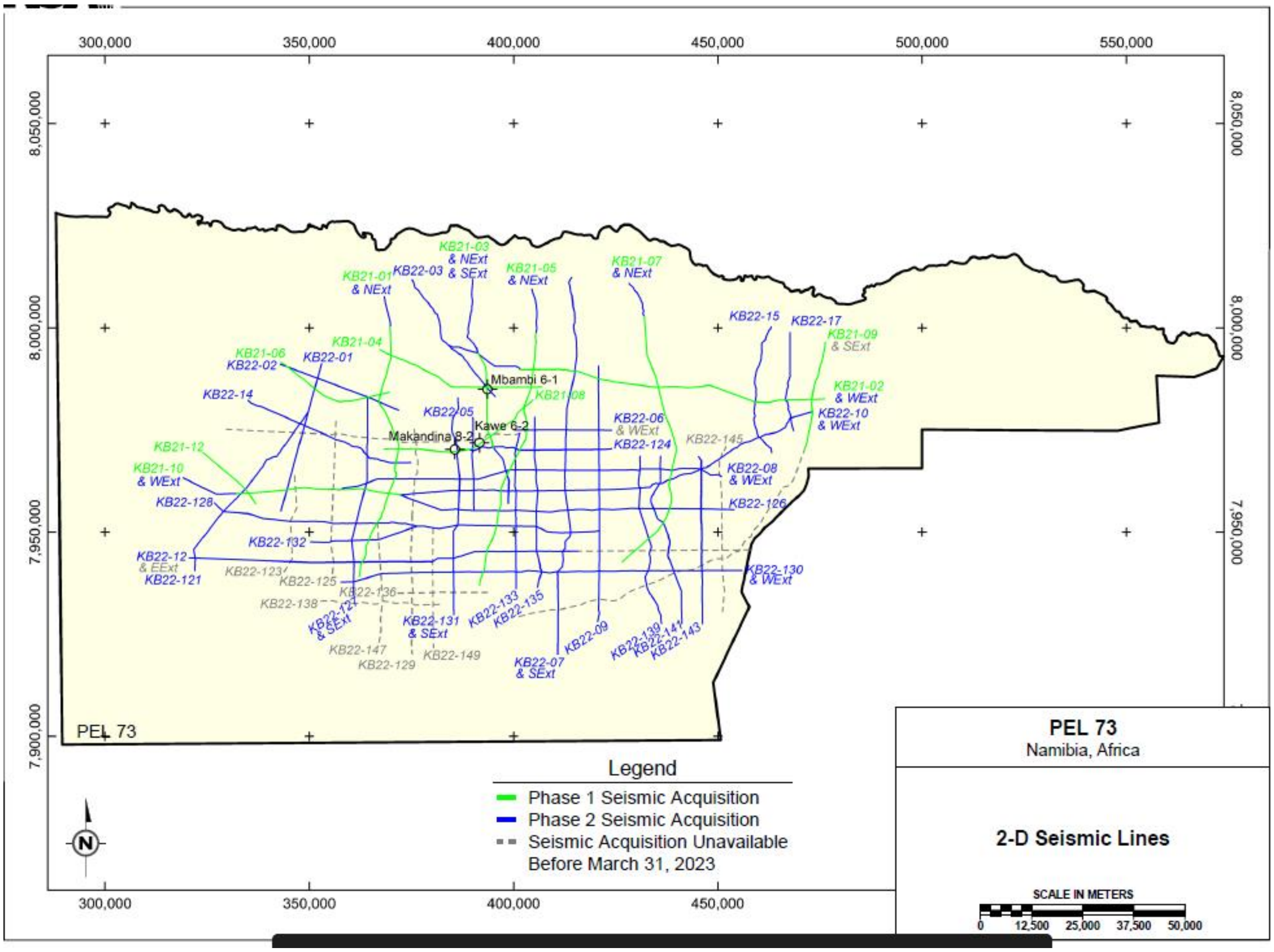
Each prospect and lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect or lead drilling outcomes. If petroleum discoveries are made, smaller-volume prospects and leads may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.
Opportunities in the Damara play area were also evaluated based on available geologic and geochemical data to determine the likely hydrocarbon fluid type, whether oil or gas, in the event of a discovery. For the Updated Report, prospective resources volumes for the Damara play area within the Otavi and Mulden Groups are summarized as potential oil discoveries due to recent reassessment of available data. However, prospective resources volumes for the Damara play area are also summarized as potential gas discoveries in the appendix to the Updated Report.

Regarding infrastructure, this area of northeast Namibia has good overall infrastructure, including transportation, communications and services. There is no oil or gas production infrastructure at this time. There is a very strong market for local power generation for Namibia and for all of southern Africa. It is premature at this time to estimate total cost and time to achieve commercial production. Development of the Company's Namibian assets is based on a predevelopment study.

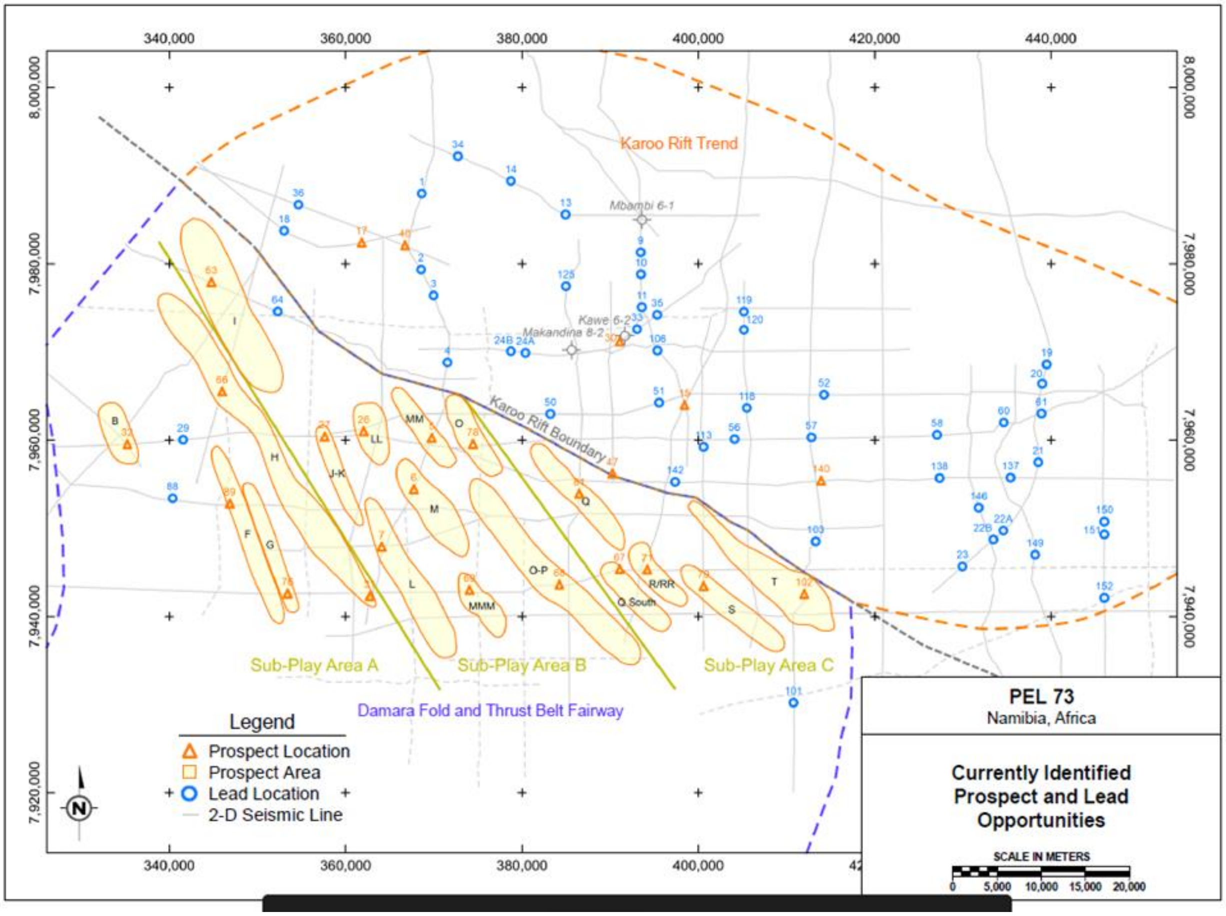
The Updated Report includes a discussion, a location map, pertinent figures, a summary of reservoir parameters, summaries of prospective resources, and a bibliography. Also included is an alternate assessment of the estimates of in-place and recoverable petroleum for the Damara play area assuming all exploration opportunities included in this report result in gas discoveries instead of oil discoveries. The following pages include further information and descriptions; however, the reader is encouraged to review the Updated Report available on SEDAR+ at www.sedarplus.ca.

Location of Licenced Area in Namibia (PEL 73)

Well and Seismic Basemap (PEL 73)

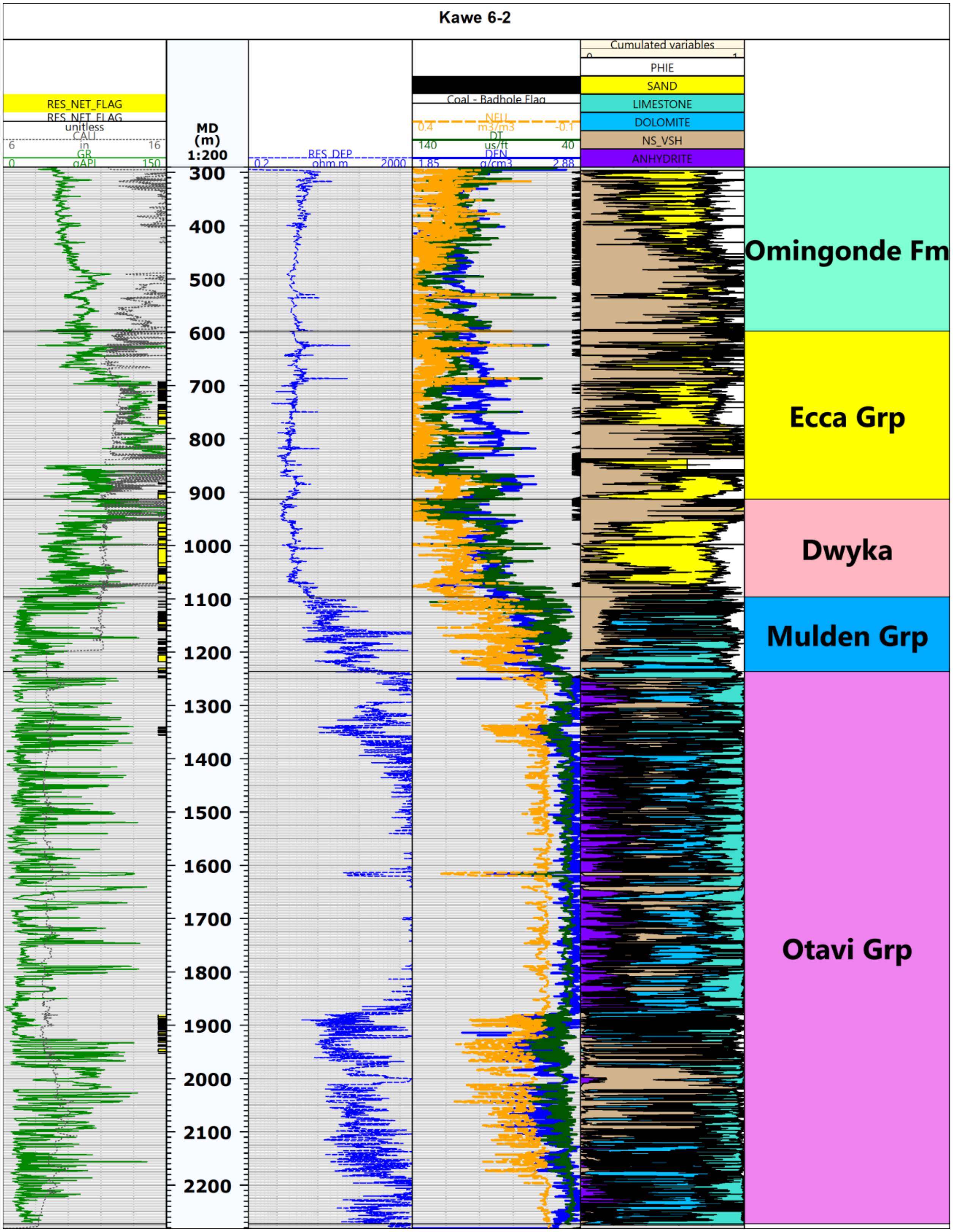


Location of Hydrocarbon Plays, Prospects and Leads



[redacted]

Kawe 6-2 Well Log, Kavango Basin, Onshore Namibia



Summary of Selected Reservoir Parameters
Damara Fold & Thrust Belt Play Area
As of March 31, 2024

Play Type	Sub-play	Target	Area[1] (acres)			Geometric Factor[2] (Decimal)			Net Pay (m)		
			P95	P50	P05	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
3	A	Upper Mulden	606 - 8,000	1,213 - 12,500	2,426 - 16,500	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	25	75	200
3	A	Lower Mulden	606 - 8,000	1,213 - 12,500	2,426 - 16,500	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	10	30	100
3	A	Otavi	606 - 6,500	1,213 - 9,500	2,426 - 13,000	0.40 - 0.70	0.60 - 0.80	0.80 - 0.90	25	50	150
3	B	Upper Mulden	873 - 11,500	1,747 - 17,250	3,493 - 23,000	0.40 - 0.50	0.60 - 0.65	0.80	10 - 25	25 - 75	50 - 200
3	B	Lower Mulden	873 - 11,500	1,747 - 17,250	3,493 - 23,000	0.40 - 0.50	0.60 - 0.65	0.80	10	30 - 50	100 - 150
3	B	Otavi	873 - 9,000	1,747 - 13,500	2,500 - 18,000	0.40 - 0.50	0.60 - 0.65	0.80	25	50	150
3	C	Upper Mulden	2,750	3,630	5,500	0.00	0.50	0.99	10	25	50
3	C	Lower Mulden	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	10	30	100
3	C	Otavi	873 - 8,000	1,747 - 10,560	3,493 - 16,000	0.40 - 0.50	0.60	0.70 - 0.80	25	50	150

Play Type	Sub-play	Target	Porosity (Decimal)			Water Saturation (Decimal)			Formation Volume Factor (rb/stb)		
			Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
3	A	Upper Mulden	0.06	0.12	0.18	0.50	0.30	0.10	1.50	1.40	1.30
3	A	Lower Mulden	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	A	Otavi	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Upper Mulden	0.06	0.12	0.18	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Lower Mulden	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	B	Otavi	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Upper Mulden	0.06	0.12	0.18	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Lower Mulden	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30
3	C	Otavi	0.05	0.08	0.12	0.50	0.30	0.10	1.50	1.40	1.30

Play Type	Sub-play	Target	Recovery Factor (Decimal)			P_g[3] (Decimal)
			Minimum	Most Likely	Maximum	
3	A	Upper Mulden	0.15	0.20	0.35	0.07 - 0.13
3	A	Lower Mulden	0.15	0.20	0.35	0.07 - 0.13
3	A	Otavi	0.15	0.20	0.35	0.07 - 0.13
3	B	Upper Mulden	0.15	0.20	0.35	0.07 - 0.13
3	B	Lower Mulden	0.15	0.20	0.35	0.07 - 0.13
3	B	Otavi	0.15	0.20	0.35	0.07 - 0.13
3	C	Upper Mulden	0.15	0.20	0.35	0.07
3	C	Lower Mulden	0.15	0.20	0.35	0.07 - 0.11
3	C	Otavi	0.15	0.20	0.35	0.07 - 0.11

(1) The ranges in P95, P50, and P05 areas reflect the variety observed in the identified opportunities, which were assessed individually.

(2) The ranges in minimum, most likely, and maximum geometric factors reflect the variety observed in the identified opportunities, which were assessed individually.

(3) The ranges in P_g reflect the variety observed in the identified opportunities, which were assessed individually.

Summary of Selected Reservoir Parameters
Karoo Rift Play Area
As of March 31, 2024

Play Type	Sub-play	Target	Area[1] (acres) P95	P50	P05	Geometric Factor[2] (Decimal) Minimum	Most Likely	Maximum	Net Pay (m) Minimum	Most Likely	Maximum
1	A	Ecca	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20	50	100
1	A	Dwyka	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20 - 25	40 - 75	60 - 150
1	B	Ecca	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20	50	100
1	B	Dwyka	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	20 - 25	40 - 75	60 - 150
2	A	Upper Mulden	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	5	20	40
2	A	Lower Mulden	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	100
2	A	Otavi	48 - 606	95 - 1,213	190 - 2,426	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	60
2	B	Upper Mulden	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	5	20	40
2	B	Lower Mulden	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	100
2	B	Otavi	97 - 2,524	194 - 5,048	388 - 10,096	0.40 - 0.50	0.60 - 0.70	0.80 - 0.90	10	30	60

Play Type	Sub-play	Target	Porosity (Decimal) Minimum	Most Likely	Maximum	Water Saturation (Decimal) Minimum	Most Likely	Maximum	Formation Volume Factor (rb/stb) Minimum	Most Likely	Maximum
1	A	Ecca	0.12	0.17	0.25	0.45	0.30	0.15	1.40	1.30	1.20
1	A	Dwyka	0.13	0.18	0.25	0.45	0.30	0.15	1.40	1.30	1.20
1	B	Ecca	0.10	0.15	0.20	0.45	0.30	0.15	1.40	1.30	1.20
1	B	Dwyka	0.11	0.16	0.20	0.45	0.30	0.15	1.40	1.30	1.20
2	A	Upper Mulden	0.06	0.12	0.18	0.50	0.35	0.25	1.50	1.40	1.30
2	A	Lower Mulden	0.06	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	A	Otavi	0.05	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Upper Mulden	0.06	0.12	0.18	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Lower Mulden	0.06	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30
2	B	Otavi	0.05	0.08	0.12	0.50	0.35	0.25	1.50	1.40	1.30

Play Type	Sub-play	Target	Recovery Factor (Decimal) Minimum	Most Likely	Maximum	P_g[3] (Decimal)
1	A	Ecca	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	A	Dwyka	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	B	Ecca	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
1	B	Dwyka	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.04 - 0.10
2	A	Upper Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	A	Lower Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	A	Otavi	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Upper Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Lower Mulden	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08
2	B	Otavi	0.10 - 0.15	0.15 - 0.20	0.25 - 0.35	0.03 - 0.08

(1) The ranges in P95, P50, and P05 areas reflect the variety observed in the identified opportunities, which were assessed individually.

(2) The ranges in minimum, most likely, and maximum geometric factors reflect the variety observed in the identified opportunities, which were assessed individually.

(3) The ranges in P_g reflect the variety observed in the identified opportunities, which were assessed individually.

Summary of Best Estimate Prospective Oil Volumes by Location
Damara Fold & Thrust Belt Play Area
As of March 31, 2024

Subclass	Location	Alternate Name	Undiscovered OOIP (MMbbl) Gross (100%)	Undiscovered OOIP (MMbbl) Company Gross[1]	Unrisked Prospective Oil Resources (MMbbl) Gross (100%)	Unrisked Prospective Oil Resources (MMbbl) Company Gross[1]	Effective P_g (Decimal)	P_d (Decimal)	Risked Prospective Oil Resources (MMbbl) Gross (100%)	Risked Prospective Oil Resources (MMbbl) Company Gross[1]	Chance of Oil[2]
Prospects											
	5	MM	440.3	396.3	88.1	79.3	0.10	0.66	5.8	5.2	Moderate
	6	M	1,113.6	1,002.3	222.7	200.5	0.11	0.69	17.2	15.4	Moderate-High
	7	L	905.7	815.1	181.1	163.0	0.13	0.66	15.0	13.5	Moderate-High
	26	LL	396.2	356.6	79.2	71.3	0.10	0.63	5.0	4.5	Moderate
	27	J-K	511.0	459.9	102.2	92.0	0.07	0.66	4.8	4.3	Moderate-High
	31	H South	1,962.7	1,766.4	392.5	353.3	0.08	0.69	22.6	20.3	Moderate-High
	32	B	683.2	614.9	136.6	123.0	0.13	0.66	11.3	10.2	Moderate-High
	63	I	1,825.6	1,643.0	365.1	328.6	0.13	0.69	31.7	28.5	Moderate
	66	H North	2,386.6	2,147.9	477.3	429.6	0.10	0.69	33.1	29.8	Moderate-High
	67	Q South	330.3	297.3	66.1	59.5	0.07	0.59	2.8	2.5	Low-Moderate
	68	O-P	1,545.8	1,391.2	309.2	278.2	0.07	0.69	15.2	13.7	Moderate-High
	69	MMM	358.7	322.8	71.7	64.6	0.08	0.63	3.7	3.4	Moderate
	71	R/RR	237.7	213.9	47.5	42.8	0.11	0.50	2.6	2.4	Low-Moderate
	76	G	842.0	757.8	168.4	151.6	0.11	0.66	12.3	11.1	Moderate-High
	78	O	671.0	603.9	134.2	120.8	0.07	0.66	6.3	5.7	Moderate
	79	S	347.9	313.1	69.6	62.6	0.07	0.63	2.9	2.6	Low-Moderate
	81	Q	347.3	312.5	69.5	62.5	0.07	0.63	3.1	2.8	Low-Moderate
	89	F	1,463.8	1,317.4	292.8	263.5	0.10	0.69	20.3	18.3	Moderate-High
	102	T	748.8	673.9	149.8	134.8	0.10	0.66	9.9	8.9	Low-Moderate
Total Prospects			**17,118.1**	**15,406.2**	**3,423.6**	**3,081.2**			**225.6**	**203.0**	
Leads											
	29	-	267.1	240.4	53.4	48.1	0.08	0.53	2.3	2.1	Moderate-High
	64	-	189.1	170.1	37.8	34.0	0.07	0.46	1.2	1.1	Moderate
	88	-	185.7	167.1	37.1	33.4	0.07	0.46	1.2	1.0	Moderate-High
	101	-	123.6	111.3	24.7	22.3	0.10	0.33	0.8	0.7	Low-Moderate
Total Leads			**765.4**	**688.9**	**153.1**	**137.8**			**5.5**	**5.0**	

Totals may not add because of rounding.

Notes: In-place volumes are reported at surface conditions. Totals of in-place volumes and unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convienence only.

[1] Company Gross volumes are ReconAfrica's working interest share of the estimated gross (100%) volumes.

[2] Each prospect has the possibility to discover oil or gas. Chance of oil is based on techincal data available at the time of the evaluation and represents the likelihood that if a discovery is made, the fluid type would be oil.

Summary of Best Estimate Prospective Oil Volumes by Location
Karoo Rift Play Area
As of March 31, 2024

		Undiscovered OOIP (MMbbl)		Unrisked Prospective Oil Resources (MMbbl)		Effective P_g	P_d	Risked Prospective Oil Resources (MMbbl)	
Subclass	Location	Gross (100%)	Company Gross[1]	Gross (100%)	Company Gross[1]	(Decimal)	(Decimal)	Gross (100%)	Company Gross[1]
Prospects									
	15	1,354.2	1,218.8	270.8	243.8	0.09	0.66	17.0	15.3
	17	365.6	329.0	69.2	62.3	0.08	0.53	3.1	2.8
	30	152.0	136.8	25.8	23.2	0.06	0.56	0.9	0.8
	40	170.3	153.3	27.3	24.6	0.05	0.40	0.5	0.5
	47	159.3	143.4	28.0	25.2	0.07	0.17	0.3	0.3
	140	316.5	284.9	63.3	57.0	0.10	0.56	3.4	3.1
Total Prospects		**2,518.0**	**2,266.2**	**484.5**	**436.1**			**25.2**	**22.7**
Leads									
	1	191.5	172.3	38.3	34.5	0.06	0.30	0.7	0.6
	2	242.3	218.0	41.6	37.5	0.05	0.36	0.7	0.6
	3	205.1	184.6	30.8	27.7	0.04	0.33	0.4	0.3
	4	51.6	46.4	10.3	9.3	0.06	0.46	0.3	0.2
	9	161.7	145.6	25.6	23.0	0.04	0.30	0.3	0.3
	10	158.8	142.9	27.9	25.1	0.05	0.40	0.5	0.5
	11	130.2	117.2	22.2	19.9	0.05	0.53	0.6	0.5
	13	99.7	89.8	19.9	18.0	0.06	0.43	0.5	0.4
	14	196.1	176.5	35.4	31.8	0.05	0.20	0.4	0.3
	18	190.7	171.7	31.3	28.2	0.04	0.23	0.3	0.3
	19	213.0	191.7	42.6	38.3	0.06	0.36	0.9	0.8
	20	158.3	142.5	31.7	28.5	0.06	0.17	0.3	0.3
	21	370.6	333.5	74.1	66.7	0.06	0.59	2.5	2.3
	22A	869.4	782.4	173.9	156.5	0.06	0.66	6.6	5.9
	22B	563.1	506.8	112.6	101.4	0.06	0.63	4.1	3.6
	23	232.3	209.0	34.8	31.4	0.04	0.33	0.4	0.4
	24A	222.5	200.3	40.7	36.6	0.05	0.33	0.7	0.6
	24B	170.4	153.4	30.2	27.2	0.05	0.26	0.4	0.4
	33	28.8	25.9	5.8	5.2	0.06	0.23	0.1	0.1
	34	222.3	200.0	40.6	36.6	0.05	0.30	0.6	0.6
	35	86.4	77.8	17.3	15.6	0.06	0.40	0.4	0.4
	36	166.5	149.9	26.5	23.9	0.04	0.53	0.6	0.5
	50	148.4	133.5	22.9	20.6	0.04	0.46	0.4	0.4
	51	51.9	46.7	10.4	9.3	0.06	0.46	0.3	0.2
	52	222.0	199.8	40.6	36.5	0.05	0.36	0.8	0.7
	56	113.4	102.1	18.8	17.0	0.05	0.43	0.4	0.3
	57	109.6	98.7	18.0	16.2	0.05	0.36	0.3	0.3
	58	115.9	104.3	23.2	20.9	0.06	0.33	0.4	0.4
	60	116.4	104.8	23.3	21.0	0.06	0.33	0.4	0.4
	61	209.1	188.2	41.8	37.6	0.06	0.36	0.9	0.8
	103	207.8	187.0	33.5	30.1	0.04	0.36	0.5	0.5
	106	147.9	133.1	22.9	20.6	0.04	0.56	0.5	0.5
	113	131.8	118.6	22.4	20.2	0.05	0.53	0.6	0.5
	118	74.1	66.7	14.8	13.3	0.06	0.50	0.4	0.4
	119	128.4	115.5	21.9	19.7	0.05	0.53	0.6	0.5
	120	73.6	66.2	14.7	13.2	0.06	0.50	0.4	0.4
	125	113.9	102.5	22.8	20.5	0.06	0.43	0.6	0.5
	137	205.8	185.2	30.9	27.8	0.04	0.23	0.3	0.2
	138	192.6	173.4	31.8	28.6	0.04	0.23	0.3	0.3
	142	205.5	185.0	30.8	27.7	0.04	0.43	0.5	0.4
	146	705.6	635.0	141.1	127.0	0.06	0.66	5.4	4.8
	149	205.3	184.7	30.8	27.7	0.04	0.23	0.3	0.2
	150	147.1	132.4	22.7	20.4	0.04	0.46	0.4	0.4
	151	147.2	132.5	22.7	20.4	0.04	0.53	0.5	0.4
	152	147.1	132.4	25.6	23.0	0.05	0.46	0.6	0.5
Total Leads		**8,851.7**	**7,966.5**	**1,602.5**	**1,442.3**			**37.8**	**34.0**

Totals may not add because of rounding.

Notes: In-place volumes are reported at surface conditions. Totals of in-place volumes and unrisked prospective resources beyond the prospect and lead levels are not reflective of volumes that can be expected to be recovered and are shown for convienence only.

[1] Company Gross volumes are ReconAfrica's working interest share of the estimated gross (100%) volumes.