STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

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 April 28, 2022. The effective date of the information provided in this Statement is December 31, 2021, unless otherwise indicated. The information contained herein was prepared on April 27, 2022.

Caution Regarding Forward-Looking Information

This Statement contains forward-looking information within the meaning of applicable Canadian securities regulations, including the Company's future plans. The use of any of the words "target", "plans", "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking information. Such forward-looking information includes, but is not limited to, statements pertaining to or in respect of, or relating to, estimates of the crude oil and natural gas reserves and prospective resources the Company may have on its properties, the value of future net revenue from the crude oil and natural gas reserves on the Company's properties, including the pricing assumptions used with respect to the net present values of future net revenue and the inflation rates used for operating and capital costs in connection therewith, estimates with respect to abandonment and reclamation costs, the Company's expectations as to the payment of taxes for the year ending December 31, 2021, for the foreseeable future and for the life of the Total Proved Reserves (as defined herein), the interpretation and analysis of data, results and samples from the 6-1 and 6-2 wells and the Company's 2D seismic program, the Company beginning the second phase of drilling in 2022 using locations that integrated in the recently acquired 2D seismic data, production testing being performed on the 6-1 and 6-2 wells at a future date, work completed by Worldwide Geochemistry, Houston on the 6-2 well highlighting three potential hydrocarbon bearing zones, the petrophysical study of the Kavango basin by Netherland Sewell & Associates Inc. identifying five potential conventional reservoir zones and the characteristics of such zones, interpretations of the combined 6-2 wellbore data and 2D seismic data identifying 6-2 as a viable sidetrack candidate with potential hydrocarbon accumulation, results following further analysis of well core data from the 6-1 well, the seismic data providing the Company with a target rich environment for its upcoming drilling program, interpretations of the integrated seismic data and processed VSPs and early processing results of the seismic program. Forward-looking information is based on management's expectations regarding future growth, results of operations, future capital and other expenditures (including the amount, nature and sources of funding for such expenditures), business prospects and opportunities. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks and uncertainties include, but are not limited to: the risks associated with the acquisition of oil and gas rights over properties which the Company has submitted applications and believes to be prospective, risks relating to oil and gas production (including, but not limited to, operational risks with resource processing), delays or changes in plans with respect to licences for oil and gas rights on such properties, costs and expenses, health, safety and environmental risks, reliance on key personnel, the absence of dividends, competition, market volatility, the risk of commodity price and foreign exchange rate fluctuations, risks and uncertainties associated with securing necessary regulatory approvals and financing to proceed with any planned work programs, risks and uncertainties related to carrying on business in foreign countries, risks and uncertainties regarding the existence of potential oil or gas reserves or the ability to economically extract any such reserves from exploration properties, and risks and uncertainties related to infectious diseases or outbreaks of viruses, as well as those additional risk factors described under the heading "*Risk Management & Risk Factors*" of the Company's management discussion and analysis for the year ended December 31, 2021. Although the Company has attempted to take into account important factors that could cause actual results to differ materially from those anticipated, there may be other factors that cause the results of the Company's business not to be as anticipated, estimated or intended. There can be no assurance that such statements will prove to be accurate as actual results and future events could differ materially from those anticipated in such statements. The forward-looking information included in this Statement is expressly qualified in its entirety by this cautionary statement. Accordingly, readers should not place undue reliance on forward-looking information.

The Company undertakes no obligation to publicly update or review the forward-looking information whether as a result of new information, future events or otherwise. Historical results of operations and trends that may be inferred from the above discussions and analysis may not necessarily indicate future results from operations.

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

ReconAfrica, engaged Netherland, Sewell & Associates, Inc. (“NSAI”), an independent qualified reserves evaluator, to prepare a report relating to the Company’s reserves as of December 31, 2021. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated. The Company’s licences located in Northeast Namibia and Northwest Botswana are set out in the Appendix to this Statement including a summary of the estimation of prospective resources of the Company as of December 31, 2021.

The Company’s crude oil and natural gas reserves are located in Chiapas, Mexico, and were acquired via the acquisition of Renaissance Oil Corp. (“Renaissance”) on July 27, 2021.. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at December 31, 2021 as evaluated by NSAI in its report dated April 27, 2022 (the "NSAI Report"). The NSAI Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the NSAI Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the NSAI Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

Summary of Oil & Gas Reserves
As of December 31, 2021
Forecast Prices and Costs

Reserves Category	Crude Oil		Conventional Natural Gas				Total BOE	
	Light and Medium Crude Oil Combined[(1)]		Solution Gas		Non-Associated Gas			
	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MBOE)	Net (MBOE)
Proved Developed Producing	344	84	2,023	782	5,169	792	1,542	347
Proved Undeveloped	443	152	4,377	1,692	0	0	1,173	434
Total Proved	**787**	**237**	**6,400**	**2,474**	**5,169**	**792**	**2,715**	**781**
Probable	259	68	1,735	667	2,811	430	1,017	251
Total Proved Plus Probable	**1,046**	**305**	**8,134**	**3,141**	**7,979**	**1,222**	**3,732**	**1,032**
Possible	286	70	1,737	666	3,409	513	1,144	267
Total Proved Plus Probable Plus Possible	**1,332**	**375**	**9,872**	**3,807**	**11,388**	**1,734**	**4,875**	**1,299**

(1) Includes condesate reserves

Summary of Net Present Values of Future Net Revenue
As of December 31, 2021
Forecast Prices and Costs

Reserves Category	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (% /Year)					After Income Taxes Discounted at (% /Year)					Unit Value Before Income Tax Discounted at 10% /Year
	0 (M$US)	5 (M$US)	10 (M$US)	15 (M$US)	20 (M$US)	0 (M$US)	5 (M$US)	10 (M$US)	15 (M$US)	20 (M$US)	($US/BOE)
Proved											
Developed Producing	8,859	7,990	7,278	6,687	6,191	6,178	5,568	5,067	4,650	4,300	4.72
Undeveloped	12,442	9,410	7,233	5,632	4,428	8,682	6,461	4,851	3,654	2,745	6.17
Total Proved	**21,301**	**17,399**	**14,511**	**12,319**	**10,619**	**14,861**	**12,029**	**9,918**	**8,305**	**7,045**	**5.34**
Probable	8,021	5,581	4,032	3,011	2,315	5,629	3,919	2,833	2,118	1,630	3.96
Total Proved Plus Probable	**29,322**	**22,980**	**18,544**	**15,331**	**12,934**	**20,490**	**15,948**	**12,751**	**10,423**	**8,675**	**4.97**
Possible	7,823	5,058	3,430	2,428	1,784	5,278	3,453	2,361	1,681	1,242	3.00
Total Proved Plus Probable Plus Possible	**37,144**	**28,038**	**21,974**	**17,758**	**14,719**	**25,768**	**19,401**	**15,113**	**12,104**	**9,916**	**4.51**

Notes:

NPV of FNR includes all resource income:
- Sale of oil, gas, by-product reserves
- Processing third party reserves
- Other income

Income Taxes
- Includes all resource income
- Applies appropriate income tax calculations
- Includes prior tax pools

Unit Values are based on net reserve volumes

BOE Equivalent: 6 Mcf = 1 BOE

Total Future Net Revenue (undiscounted)
As of December 31, 2021
Forecast Prices and Costs

Reserves Category	Revenue (M$US)	Royalties [(1)] (M$US)	Operating Costs (M$US)	Development Costs (M$US)	Abandonment & Reclamation Costs (M$US)	Future Net Revenue Before Income Taxes (M$US)	Income Taxes (M$US)	Future Net Revenue After Income Taxes (M$US)
Proved	109,191	80,132	2,719	4,300	738	21,301	6,390	14,911
Proved Plus Probable	150,233	111,960	3,913	4,300	738	29,322	8,796	20,525
Proved Plus Probable Plus Possible	198,489	150,548	5,758	4,300	738	37,144	11,291	25,853

(1) Includes Royalties plus Exploration & Production Activities Tax

Future Net Revenue by Production Type
As of December 31, 2021
Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% /Year (M$US)	Unit Value Before Income Taxes Discounted at 10% /Year ($US/BOE)
Proved	Light and Medium Crude Oil Combined [(1)]	12,025	7.04
	Conventional Natural Gas [(2)]	2,630	2.61
	Topen Abandonment	(144)	0.00
	TOTAL	**14,511**	**5.35**
Proved Plus Probable	Light and Medium Crude Oil Combined [(1)]	15,175	6.99
	Conventional Natural Gas [(2)]	3,512	1.33
	Topen Abandonment	(144)	0.00
	TOTAL	**18,544**	**3.86**
Proved Plus Probable Plus Possible	Light and Medium Crude Oil Combined [(1)]	17,930	6.81
	Conventional Natural Gas [(2)]	4,187	1.59
	Topen Abandonment	(144)	0.00
	TOTAL	**21,974**	**4.17**

Notes:

Unit Values are based on net reserve volumes

(1) Net oil revenue includes revenue from solution gas and associated by-products.

(2) Net gas revenue includes revenue from associated by-products (condensate).

BOE Equivalent 6 Mcf = 1 BOE

3. PRICING ASSUMPTIONS

The pricing assumptions used in the NSAI Report with respect to net present values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. NSAI is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

Summary of Pricing Assumptions
As of December 31, 2021

Year	Benchmark Oil/Condensate Price ($US/bbl)	Oil/Condensate Differential(1)	Average Received Oil/Condensate Price ($US/bbl)	Benchmark Gas Price ($US/MMBtu)	Gas Price Differential(2)	Average Received Gas Price ($US/Mcf)
Historical(3)						
2021	66.55(4)	(3.49)	63.06	3.598(5)	1.484	5.082
Forecast(6)						
2022	72.83	(3.49)	69.34	3.850	1.484	5.334
2023	68.78	(3.49)	65.29	3.438	1.484	4.922
2024	66.76	(3.49)	63.27	3.174	1.484	4.658
2025	68.09	(3.49)	64.60	3.236	1.484	4.720
2026	69.45	(3.49)	65.96	3.303	1.484	4.787
2027	70.84	(3.49)	67.35	3.367	1.484	4.851
2028	72.26	(3.49)	68.77	3.435	1.484	4.919
2029	73.70	(3.49)	70.21	3.505	1.484	4.989
2030	75.18	(3.49)	71.69	3.575	1.484	5.059
2031	76.68	(3.49)	73.19	3.646	1.484	5.130
Thereafter, an escalation rate of 2.0% percent per year applied to Benchmark prices for inflation						

(1) Oil/Condensate differential is based on the historical accounting records of ReconAfrica and is inclusive of adjustments for quality and market differentials

(2) Gas differential is based on the historical accounting records of ReconAfrica and is inclusive of adjustments for energy content and market differentials

(3) Prices used in Constant Case

(4) 12-month unweighted arithmetic average of the first-day-of-the-month West Texas Intermediate spot price for each month in the period January through December 2021

(5) 12-month unweighted arithmetic average of the first-day-of-the-month Henry Hub spot price for each price for each month in the period January through December 2021

(6) Forecast Benchmark prices are an average of three December 31, 2021, forecasts prepared by Canadian independent consultants. Oil/Condensate prices are based on NYMEX West Texas Intermediate near-month prices; Gas prices are based on NYMEX Henry Hub near-month prices.

4. RECONCILIATION OF CHANGES IN RESERVES

Reconciliation of Company Gross[1] Reserves by Product Type
As of December 31, 2021
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 (Mstb)	Gross Probable (Mstb)	Gross Proved Plus Probable (Mstb)	Gross Possible (Mstb)	Gross Proved Plus Probable Plus Possible (Mstb)	Gross Proved (Mstb)	Gross Probable (Mstb)	Gross Proved Plus Probable (Mstb)	Gross Possible (Mstb)	Gross Proved Plus Probable Plus Possible (Mstb)
December 31, 2020	**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**
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	835.4	259.2	1,094.6	286.0	1,380.6	12,338.8	4,545.1	16,883.9	5,146.2	22,030.0	2,891.9	1,016.7	3,908.6	1,143.6	5,052.3
Dispositions	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
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[3]	(48.6)	0.0	(48.6)	0.0	(48.6)	(770.3)	0.0	(770.3)	0.0	(770.3)	(177.0)	0.0	(177.0)	0.0	(177.0)
December 31, 2021	**786.8**	**259.2**	**1,046.0**	**286.0**	**1,332.0**	**11,568.5**	**4,545.1**	**16,113.6**	**5,146.2**	**21,259.7**	**2,714.9**	**1,016.7**	**3,731.6**	**1,143.6**	**4,875.3**

(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.

(3) All production figures refer to production subsequent to the date of acquistion, covering the period from July 27 to December 31, 2021

5. ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a discussion of risk factors and uncertainties affecting reserves data, see Risk Management & Risk Factors – Reserve Estimates and Reserve Replacement Risks in the Management's Discussion and Analysis for the year ended December 31, 2021.

6. OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Mundo Nuevo
The Mundo Nuevo block is located onshore 42 km southwest of the city of Villahermosa, Tabasco with an areal extent of 27.7 km^2 (6,845 acres). The Mundo Nuevo field, a middle Cretaceous fractured carbonate reservoir, was discovered in 1977. This field was developed by Mexico's state-owned oil and gas company, Pemex, through the drilling of 14 wells, reaching peak production of over 15,000 barrels per day (bbls/day) of light crude oil, in the early 1980's, with an average reservoir depth of 3,580 meters. The Mundo Nuevo field is currently producing light crude oil and natural gas from one well which is transported from the field in a pipeline for sale. Renaissance was awarded the Mundo Nuevo block with an additional royalty amount of 80.69%.

Malva
The Malva block is located onshore 61 km southwest of the city of Villahermosa, Tabasco with an areal extent of 21.2 km^2 (5,239 acres) The Malva field, an upper Cretaceous limestone reservoir, was discovered in 2003. This field was developed by Pemex through the drilling of 4 wells, reaching peak production of over 2,000 barrels bbls/day of light crude oil, in the late 2000's, with an average reservoir depth of 2,680 meters. The Malva field is currently producing light crude oil and natural gas from one well which is transported from the field in a pipeline for sale. Renaissance was awarded the Malva block with an additional royalty amount of 57.39%.

Properties with No Attributed Reserves

Topén
The Topén block is located onshore 45 km southwest of the city of Villahermosa, Tabasco with an areal extent of 25.3 km^2 (6,251 acres). The Topén field, an upper Cretaceous fractured carbonate reservoir, was discovered in 1978. This field was developed by Pemex through the drilling of 5 wells, reaching peak production of over 1,500 barrels bbls/day of medium crude oil, in the mid 1980's, with an average reservoir depth of 3,300 meters. Renaissance was awarded the Topén block with an additional royalty amount of 78.79.

Pontón
The Pontón block is located onshore 25 km southeast of Panuco city, Veracruz, with an areal extent of 12 km^2 (2,965 acres). The Pontón field was discovered and put into production in 1971 in the Upper Jurassic San Andres formation. In May 1991, production commenced in the Lower Cretaceous Tamaulipas Inferior formation. This field was developed by Pemex, through the drilling of 14 wells in the 1970s. Although not currently producing, Pontón has cumulatively produced approximately 800,000 barrels of light oil (34° API). The Upper Jurassic San Andres formation has an average reservoir depth of 1,266 meters and the Lower Cretaceous Tamaulipas Inferior formation has an average reservoir depth of 925 meters. On July 13, 2017, Renaissance was awarded its request for force majeure for the Pontón block, allowing for a temporary suspension of development operations to facilitate the remediation by the previous operator of certain areas of the Pontón block that incurred surface contamination from previous oil field activities. Under the terms of the licences for all of Renaissance's operated blocks in Mexico, previous operators are responsible for

the remediation of all pre-existing damages identified and documented by Renaissance. Renaissance was awarded the Pontón block with an additional royalty amount of 21.39%.

Namibia

ReconAfrica holds a 90% interest in a petroleum exploration licence in northeast Namibia which covers the entire Kavango sedimentary basin (the "Namibia Licence"). The National Petroleum Company of Namibia ("NAMCOR"), a Namibian state-owned entity, holds the remaining 10% interest in the Namibia Licence on a carried interest basis. The Namibia Licence, which is governed by the terms of a Petroleum Agreement between the Company and the Namibia Ministry of Mines and Energy (the "MME") dated January 26, 2015, provides the Company with the exclusive right to conduct exploration activities on certain licenced property covering an area of approximately 25,341.33 km^2 (6.3 million acres, 5.6 million net acres) and based on commercial success, it entitles ReconAfrica to obtain a 25-year production licence.

The Petroleum Agreement describes an eight-year exploration work program and accompanying minimum expenditures on the Namibia Licence related thereto. Such exploration program consists of the following three phases:

- Initial Exploration Period (4 years): minimum expenditure of US$5,000,000 including a requirement 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.
- First Renewal Exploration Period (2 years): minimum expenditure of US$10,000,000 including a requirement 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.
- Second Renewal Exploration Period (2 years): minimum expenditure of US$10,000,000 including a requirement 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 MME granted a one-year extension to the Initial Exploration Period of the Namibia Licence.

Pursuant to an adjustment letter dated February 25, 2019, the MME 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 would be deemed to have been satisfied provided that, by January 29, 2020, the Company drill one stratigraphic test well, rather than two. The drilling of one stratigraphic test well would 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 was deferred to and became 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 was deferred into the First Renewal Exploration Period.

On December 24, 2019, the Company announced that Namibia's Minister of Energy and Mines had 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. The MME's approval included recognition that the proposed work program for the First Renewal Exploration Period included the drilling of two stratigraphic test wells. On September 23, 2021, the First Renewal Exploration Period was further extended due to the COVID-19 pandemic such that it now continues until January 29, 2023.

In addition to the aforementioned minimum exploration expenditure, the Company is required to pay to the Government of Namibia an annual licensing fee ranging from NAD$60 to NAD$150 per square kilometer of Namibia Licensed Property, depending on the applicable stage of exploration. Should the Namibian Minister of Energy and Mines 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 kilometer to which such production licence relates.

During the year ended December 31, 2021, ReconAfrica satisfied the work requirements of the First Renewal Exploration Period.

In accordance with the Petroleum Agreement, as adjusted by the February 25, 2019 adjustment letter, the Company must relinquish at least 50% of the exploration area covered by the Namibia Licence no later than either (i) 60 days following the completion of the drilling of the second stratigraphic test well; or (ii) at the end of the First Renewal Exploration Period, to be agreed upon between the MME and the Company. A further 25% of the exploration area covered by the Namibia Licence must also be relinquished by the Company no later than 30 days before the end of the First Renewal Exploration Period following the grant of the Namibia Licence. 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.

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.sedar.com. See "*Material Contracts*" in the Company's annual information form for the year ended December 31, 2020.

Botswana

In June 2020, the Company was granted a petroleum licence in northwestern Botswana for 2.22 million acres (8,990 km^2). Terms of the 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*
- The Company has committed to a minimum work program of US$432,000 over the first 4-year exploration period

ReconAfrica has excluded a number of environmentally sensitive areas from the area of the Botswana license, including the Tsodilo Hills. Additionally, the project has set no-go and buffer zones to protect water that include a 10-km setback from the Okavango River and a 20-km setback from the Okavango Delta.

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 December 31, 2021 and related management's discussion and analysis.

Abandonment and Reclamation Costs

Abandonment and reclamation costs based on the Company's estimates were included in the NSAI Report at the property level for existing wells with reserves assigned and existing material, dedicated facilities. For leases that are projected to be active on or after December 31, 2021, net abandonment and reclamation coasts are scheduled to be incurred 1 year after the end of the economic life of the lease. For leases that are projected to be no longer active as of December 31, 2021, net abandonment and reclamation costs are scheduled to be incurred over the next 5 years. Capital costs and abandonment and reclamation costs are not escalated for inflation.

The total abandonment cost in respect of proved reserves using forecast prices is $638,200 (undiscounted). 100% of such amounts were deducted as abandonment costs in estimating the Company's future net revenue as disclosed above.

Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Forward Contracts

Currently there are no material forward contracts or commitments.

Tax Horizon

The Company does not anticipate having taxes payable for the year ending December 31, 2021. Based on current estimates of the Company's future taxable income and levels of tax-deductible expenditures including royalties, management believes that the Company will not be required to pay cash income taxes for the life of the Total Proved Reserves.

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 the Chiapas blocks, no property acquisition, exploration or development expenditures were incurred other than field maintenance and evaluation expenditure during the year ended December 31, 2021. For information on exploration and development costs please refer to Note 6 of the Company's consolidated financial statements for the year ended December 31, 2021 and related management's discussion and analysis.

Exploration and Development Activities

During the year ended December 31, 2021, Renaissance incurred $960,510 in resource property evaluation expenditures for its licences in Chiapas, Mexico. None of these costs were capitalized in exploration and evaluation assets in the statement of financial position as at December 31, 2021. No drilling of new wells or work overs to existing wells were completed during the year.

During the year ended December 31, 2021, the Company drilled the 6-2 and 6-1 wells in Namibia and completed a seismic program to satisfy the requirements of the First Renewal Exploration Period. The primary objective of the well drilling program was to confirm a thick, active, petroleum system throughout the deep Kavango basin. Specifically, the wells were designed to test organic source rock and more shallow conventional structures throughout the sedimentary basin.

The initial drilling results of two stratigraphic test wells in the Kavango basin confirmed the presence of conventional and migrated petroleum. These results have led the Company to target those resources, as they are typically less expensive to develop and produce higher value, higher volume of petroleum than unconventional resources. Therefore, prospective resource data, as included in the Appendix, includes only conventional resource estimates.

Highlights from the drilling of the 6-2 and 6-1 wells are as follows:

- The 6-2 well and the 6-1 well reached total depths of 2,294 meters (7,526 feet) and 2,780 meters (9,121 feet) respectively.
- The 6-2 well had over 250 meters (820 feet) of hydrocarbon shows while the 6-1 had over 350 meters (1,148 feet) of hydrocarbon shows.
- Both wells had full logging suites, extensive sidewall cores in addition to the full sample analysis of cuttings, and hydrocarbon shows, and were completed to enable the running of vertical seismic, and potential for re-entry production testing at a later date.
- The Company has now completed all drilling components required to satisfy the work program requirements for an extension of the exploration period on PEL 73.
- The Company will begin second phase of drilling in 2022 using locations that were identified through the recently acquired Phase 1, 2D seismic data.

<u>Kawe 6-2 Well:</u>
The first stratigraphic test well, the 6-2 in Kawe, Namibia, was drilled to a final depth of 2,294 meters (7,526 feet). The well was left in a state that allows it to be re-entered to run a Vertical Seismic Profile ("VSP") and test potential zones of interest. A total of over 250 meters (820 feet) of conventional migrated light oil, natural gas and natural gas liquids were encountered over three zones. Work completed by Worldwide Geochemistry, Houston, on the 6-2 well highlighted three potential hydrocarbon bearing zones, fluid types, hydrocarbon migration, characteristics, and the potential for production testing.

In September 2021, Core Laboratories ("Core Lab") provided initial analysis of the cores taken from the 6-2 well, and Netherland Sewell & Associates Inc. used this data to calibrate log analysis to provide the first petrophysical study of the Kavango basin. The petrophysical study identified what the Company believes are five potential conventional reservoir zones in the 6-2 well, of which three are clastic zones (sandstone) and two are carbonate zones (limestone, dolomite) based on the first set of core analysis and mineralogical data from Core Labs. The Company believes this study, which brings together wireline log data, core data, and sample and hydrocarbon show data from the 6-2 well, confirms 198 meters (650 feet) of net conventional reservoir over five separate intervals.

The Company ran a VSP in the 6-2 well. The VSP obtains high resolution seismic information from the wellbore and is used to integrate the wellbore data into the nearby 2D Phase 1 seismic line. The VSP confirmed evidence of a significant fault observed while drilling the well. The combined 6-2 wellbore data and 2D seismic interpretation have identified 6-2 as a viable sidetrack candidate targeting an up-dip porosity interval with potential hydrocarbon accumulation.

<u>Mbambi 6-1 Well:</u>
The second stratigraphic test well, the 6-1 in Mbambi, Namibia, was drilled to a final depth of 2,780 meters (9,121 feet). Casing is set to total depth. A VSP was run in this well with a seismic line shot across its wellbore, indicating the well was drilled on a significant intra-rift fault block that was very fractured and faulted. It will be left in a state that allows it to be re-entered to run potential testing of possible production zones. A preliminary total of 350 meters (1,148 feet) of oil and natural gas shows were encountered over seven potential zones. After significant shipping issues related to global supply chains, the well core data is now in the process of being analyzed.

<u>Seismic Operations</u>
The Company completed nearly 500 linear kilometers of seismic acquisition and processing in 2021. This 2D seismic program is the first seismic acquisition project to ever be conducted in the Kavango Basin. The program was designed using very low environmental impact seismic equipment; Accelerated Weight Drop (AWD) and cable-less sensors.

With the success of the first two recently drilled stratigraphic wells confirming an active conventional petroleum system within the basin, this seismic program was designed to delineate potential traps and hydrocarbon reservoirs. Third party processing of the data by DownUnder GeoSolutions (America) LLC in Houston, Texas, and Absolute Imaging Inc. in Calgary, Canada, was completed and finalized.

Subsequent to December 31, 2021, the Company received the final processing results of the 2021 seismic program. These seismic sections show good quality seismic images of structural and stratigraphic features, which provides a target rich environment for the upcoming drilling program scheduled for the second quarter of 2022. The seismic data, integrated with the processed VSPs results for wells 6-1 and 6-2, is being interpreted in-house, and will be augmented by third party interpretation for the selection of well locations for the next round of drilling.

Where possible, this seismic campaign made use of local suppliers and businesses such as lodges, hotels, industrial yards, equipment rental agencies, vehicle rentals, communications providers, fuel distributors, PPE suppliers, and caterers.

Early processing results illustrate:

- The overall good quality of the seismic data.
- Significant extensional grabens with normal fault systems connected by steep wrench-related shear zones.
- Well-developed expansion of stratigraphic section in the grabens.
- Clear stratigraphic resolution of a variety of depositional geometries.
- Good fault resolution, some major faults extending over several thousand meters to near surface, and potential for multiple styles of trapping.
- Consistency with the rift basin origin of the Kavango basin.
- Adjacent thrust faulted and folded basin.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2022 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves:

Reserves Category(1)	**Crude Oil Combined**(2)	**Conventional Natural Gas**	**Total BOE**
	(Mstb)	**(MMcf)**	**(MBOE)**
Proved Developed Producing	97.3	1,696.0	380.0
Proved Undeveloped	0.0	0.0	0.0
Total Proved	**97.3**	**1,696.0**	**380.0**
Probable	3.8	24.7	7.9
Total Proved Plus Probable	**101.1**	**1720.7**	**387.9**

(1) Located in Chiapas, Mexico.

(2) Includes condensate volumes

Notes:

- 46% of crude oil (46Mstb) produced from the Malva field, 54% (51Mstb) from Mundo Nuevo
- 21% of gas (367MMcf) produced from the Malva field, 79% (1329MMcf) from Mundo Nuevo

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.

Recent production history as follows:

	July 27 to December 31, 2021		
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Total (Boe/d)
Mundo Nuevo	175	1,011	343
Malva	143	4,024	814
	317	5,035	1,157

Average Production by Product	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Crude oil (Bbl/d)	338	-	318	-
Natural gas (Mcf/d)	5,054	-	5,037	-
Total (Boe/d)	1,180	-	1,157	-

Revenue From Product Sales	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Crude oil	$ 1,662,127	$ -	$ 2,626,048	$ -
Natural gas	2,188,862	-	3,932,676	-
Total	$ 3,850,989	$ -	$ 6,558,724	$ -

Average Prices	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Crude oil ($/bbl)	80.44	-	89.88	-
Natural gas ($/mcf)	6.69	-	8.49	-

Royalties	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Charge for the period	$ 3,089,775	$ -	$ 5,128,074	$ -
Percentage of revenue	80.2%	-	78.2%	-
Per Boe	$ 41.11	$ -	$ 48.18	$ -

Production Costs	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Charge for the period	$ 185,449	$ -	$ 484,534	$ -
Percentage of revenue	4.8%	-	7.4%	-
Per Boe	$ 2.47	$ -	$ 4.55	$ -

Operating Netback	**July 27 to September 30,**		**Three months ended Dec 31**	
	2021	**2020**	**2021**	**2020**
Revenue From Product Sales	$ 3,850,989	$ -	$ 6,558,724	$ -
Royalties	(3,089,775)	-	(5,128,074)	-
Production costs	(185,449)	-	(484,534)	-
Operating Netback	575,765	-	946,116	-
Per Boe	$ 7.66	$ -	$ 8.89	$ -

7. OPTIONAL DISCLOSURE OF PROSPECTIVE RESOURCES DATA

See Appendix.

APPENDIX

OPTIONAL DISCLOSURE OF PROSPECTIVE RESOURCES DATA

The following is a summary of the estimation of prospective resources of the Company as of December 31, 2021 as set out in the NSAI Report. The NSAI Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil & Gas Evaluation Handbook prepared jointly by the Society of Petroleum and Engineers (Calgary Chapter) (the "COGE Handbook") and in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Summary of Prospective Oil and Gas Resources

The Company has not yet established reserves on any of its Namibia or Botswana properties 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 NSAI Report.

The prospective resources herein 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 this 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 leads, as discussed in subsequent paragraphs. This report does not include economic analysis for these leads. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this 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 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 lead, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Summary of Unrisked Best Estimate Prospective Oil and Gas Resources
As of December 31, 2021

Gross (100 Percent)		Company Gross		Net(1)	
Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)
999.0	1,422.9	899.1	1,280.6	854.1	1,216.6

Summary of Risked Best Estimate Prospective Oil and Gas Resources
As of December 31, 2021

Gross (100 Percent)		Company Gross		Net(1)	
Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)	Light and Medium Crude Oil (MMstb)	Conventional Natural Gas (Bcf)
73.5	32.4	62.8	27.7	59.7	26.3

Note: Prospective resources are the arithmetic sum of multiple probability distributions.

(1) Net prospective resources are after royalty deductions.

(2) 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.

Oil and condensate volumes are expressed in millions of barrels (MMbbl); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (Bcf) at standard temperature and pressure bases.

The prospective resources shown in this 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. As requested, low estimate and high estimate prospective resources have not been included in this report. For the purposes of this 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 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 estimates for risked resources are derived directly from the estimates for unrisked resources, incorporating a geologic risk assessment for each prospect; such risked resources also incorporate a development risk assessment. For resources, the chance of commerciality includes both the chance of discovery and, once a discovery is made, the chance of development. 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. 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 this report is a discussion of the primary geologic risk elements for each lead.

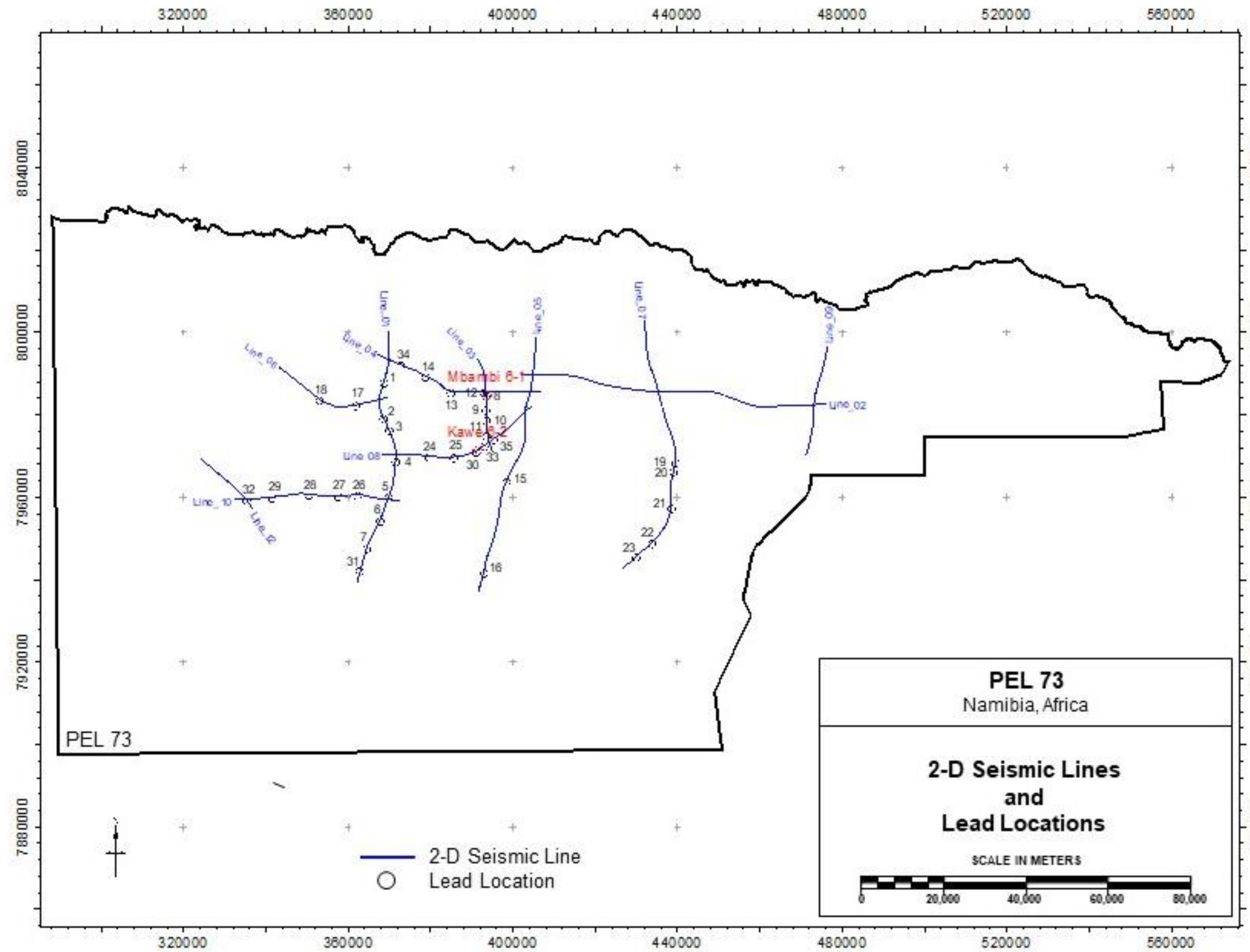
Each lead was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume leads may not be commercial to independently develop, although they 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 this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these leads.

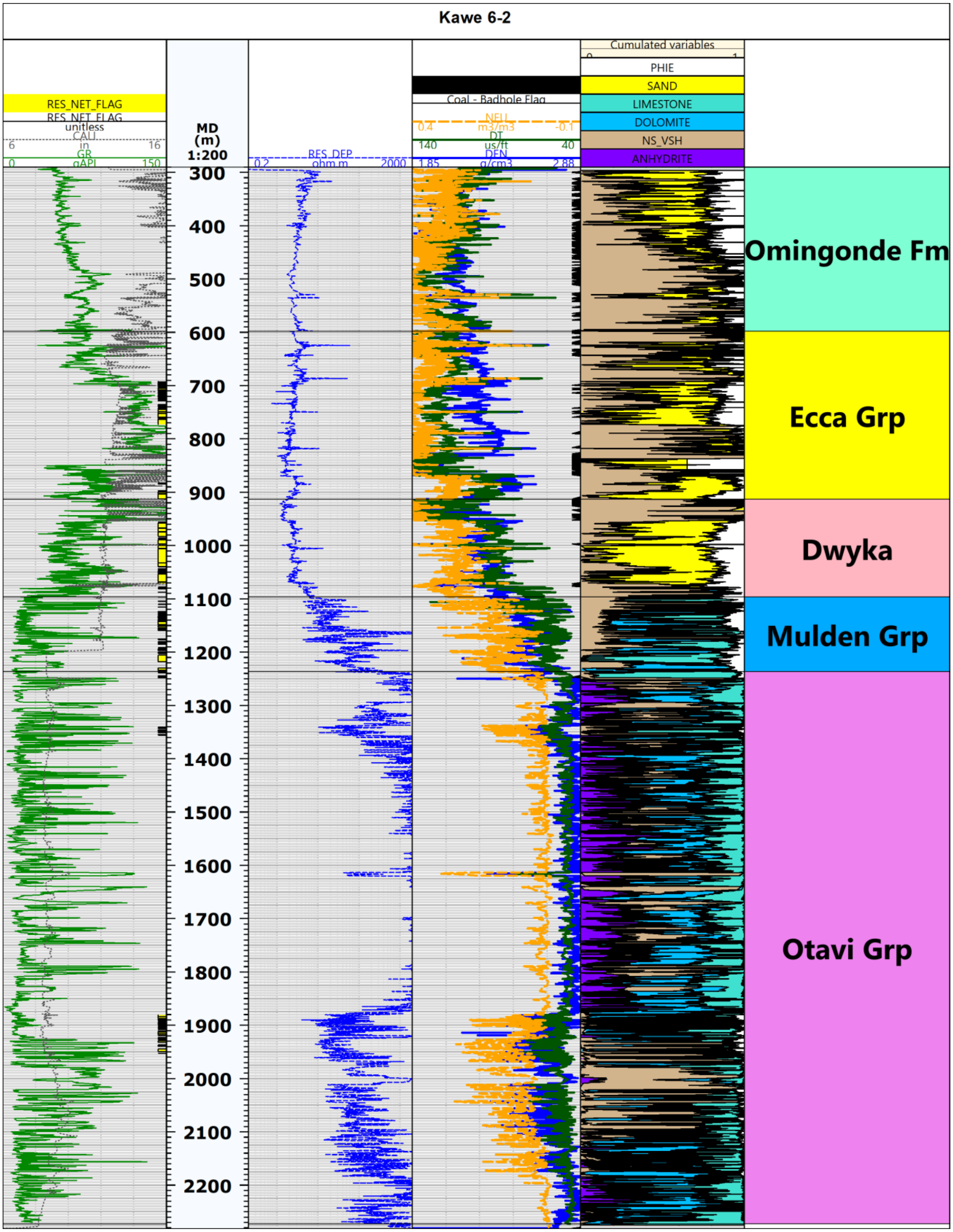
An estimate of risked net present value of future net revenue of prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes prospective resources that are considered too uncertain with respect to the chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Location of Licenced Area in Namibia (PEL 73)

2-D Seismic Lines and Lead Locations



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



Summary of Selected Reservoir Parameters
As of December 31, 2021

Play Type	Target	Reservoir Type	Trap Style	Product	Ranges of Apparent Lengths[1] (m)		Aspect Ratio			Azimuth (Degrees)	Geometric Factor (Decimal)			Gross Thickness[2] (m)
					P95	P05	P95	P50	P05		Minimum	Most Likely	Maximum	Most Likely
1	Ecca	Clastic	Structural	Oil	250 - 2,050	700 - 5,100	1	2.4	6	315	0.65	0.75	0.9	30 - 340
1	Ecca	Clastic	Stratigraphic	Oil	450 - 1,950	900 - 3,900	1	2.4	6	315	0.8	0.85	0.9	40 - 530
1	Dwyka	Clastic	Structural	Oil	250 - 2,050	700 - 5,100	1	2.4	6	315	0.65	0.75	0.9	15 - 340
1	Dwyka	Clastic	Stratigraphic	Oil	900 - 1,100	1,800 - 2,200	1	2.4	6	315	0.8	0.85	0.9	55 - 70
2	Mulden	Carbonate	Structural	Oil	250 - 2,050	700 - 5,100	1	2.4	6	315	0.65	0.75	0.9	15 - 110
2	Mulden	Carbonate	Stratigraphic	Oil	1100	2200	1	2.4	6	315	0.8	0.85	0.9	85
2	Otavi	Carbonate	Structural	Oil	250 - 2,050	700 - 5,100	1	2.4	6	315	0.65	0.75	0.9	40 - 220
2	Otavi	Carbonate	Stratigraphic	Oil	1100	2200	1	2.4	6	315	0.8	0.85	0.9	100
3	Mulden/Otavi	Carbonate	Structural	Gas	1,150 - 3,000	2,300 - 4,000	1	4	10	45	0.5	0.6	0.7	580

Play Type	Target	Reservoir Type	Trap Style	Product	Net to Gross (Decimal)			Porosity (Decimal)			Water Saturation (Decimal)		
					Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
1	Ecca	Clastic	Structural	Oil	0.15	0.3	0.45	0.12	0.17	0.25	0.15	0.3	0.45
1	Ecca	Clastic	Stratigraphic	Oil	0.15	0.3	0.45	0.12	0.17	0.25	0.15	0.3	0.45
1	Dwyka	Clastic	Structural	Oil	0.4	0.7	0.85	0.13	0.18	0.25	0.15	0.3	0.45
1	Dwyka	Clastic	Stratigraphic	Oil	0.4	0.7	0.85	0.13	0.18	0.25	0.15	0.3	0.45
2	Mulden	Carbonate	Structural	Oil	0.1	0.25	0.4	0.06	0.12	0.2	0.25	0.35	0.5
2	Mulden	Carbonate	Stratigraphic	Oil	0.1	0.25	0.4	0.06	0.12	0.2	0.25	0.35	0.5
2	Otavi	Carbonate	Structural	Oil	0.1	0.2	0.3	0.05	0.09	0.14	0.25	0.35	0.5
2	Otavi	Carbonate	Stratigraphic	Oil	0.1	0.2	0.3	0.05	0.09	0.14	0.25	0.35	0.5
3	Mulden/Otavi	Carbonate	Structural	Gas	0.1	0.2	0.3	0.05	0.09	0.14	0.25	0.35	0.5

Play Type	Target	Reservoir Type	Trap Style	Product	Formation Volume Factor				Water Saturation (Decimal)			P_g (Decimal)
					Minimum	Most Likely	Maximum	Units	Minimum	Most Likely	Maximum	
1	Ecca	Clastic	Structural	Oil	1.2	1.3	1.4	rb/stb	0.15	0.2	0.35	0.1
1	Ecca	Clastic	Stratigraphic	Oil	1.2	1.3	1.4	rb/stb	0.1	0.15	0.25	0.05
1	Dwyka	Clastic	Structural	Oil	1.2	1.3	1.4	rb/stb	0.15	0.2	0.35	0.1
1	Dwyka	Clastic	Stratigraphic	Oil	1.2	1.3	1.4	rb/stb	0.1	0.15	0.25	0.05
2	Mulden	Carbonate	Structural	Oil	1.3	1.4	1.5	rb/stb	0.15	0.2	0.35	0.08
2	Mulden	Carbonate	Stratigraphic	Oil	1.3	1.4	1.5	rb/stb	0.1	0.15	0.25	0.05
2	Otavi	Carbonate	Structural	Oil	1.3	1.4	1.5	rb/stb	0.15	0.2	0.35	0.09
2	Otavi	Carbonate	Stratigraphic	Oil	1.3	1.4	1.5	rb/stb	0.1	0.15	0.25	0.05
3	Mulden/Otavi	Carbonate	Structural	Gas	175	225	275	scf/rcf	0.55	0.65	0.75	0.04

(1)The ranges in P95 and P05 apparent lengths reflect the variety observed in the identified leads, which were assessed individually.

(2)The ranges in most likely gross thickness reflect the variety observed in the identified leads, which were assessed individually.

Summary of Best Estimate Prospective Oil Volumes by Location
As of December 31, 2021

Loc No.	Line-SP	OOIP (MMstb)	Unrisked Gross (100%) Recoverable (MMstb)	Effective P_g [1] (Decimal)	P_d (Decimal)	Risked Gross (100%) Recoverable (MMstb)
1	L01-5000	49.1	8.3	0.07	0.40	0.2
2	L01-8700	569.0	106.0	0.09	0.90	8.4
3	L01-10000	29.9	4.5	0.05	0.20	0.0[2]
4	L01-13200	25.5	5.1	0.10	0.20	0.1
8	L03-3800	48.3	9.7	0.10	0.40	0.4
9	L03-5200	38.6	7.7	0.10	0.40	0.3
10	L03-6200	55.0	9.8	0.08	0.40	0.3
11	L03-7700	42.2	7.8	0.09	0.40	0.3
12	L04-5600	4.6	0.8	0.08	0.10	0.0[2]
13	L04-8000	26.7	5.3	0.10	0.20	0.1
14	L04-11750	61.7	12.0	0.10	0.40	0.5
15	L05-14500	766.7	153.3	0.10	0.90	13.7
17	L06-3200	158.3	29.3	0.09	0.70	1.8
18	L06-6900	57.2	9.4	0.06	0.40	0.2
19	L07-14200	44.9	9.0	0.10	0.40	0.3
20	L07-15100	65.3	13.1	0.10	0.40	0.5
21	L07-18750	108.7	21.7	0.10	0.70	1.5
23	L07-24800	155.0	23.3	0.05	0.70	0.8
25	L08-7000	799.2	138.8	0.08	0.90	9.6
30	L08-9300	24.8	5.0	0.14	0.20	0.1
33	L08-10275	8.4	1.7	0.10	0.10	0.0[2]
34	L04-14420	108.0	21.1	0.09	0.70	1.4
35	L08-10275	84.9	17.0	0.10	0.70	1.2
22A	L07-22750	993.1	198.6	0.10	0.90	17.7
22B	L07-22750	658.1	131.6	0.10	0.90	11.7
24A	L08-4550	158.1	25.5	0.06	0.70	1.1
24B	L08-4550	137.3	23.5	0.07	0.70	1.2
Total		**5,278.6**	**999.0**			**73.5**

Totals may not add because of rounding

[1] Effective probability of geologic success is the volume-weighted average of multiple probabilities

[2] Risked recoverable prospective resources that exist for this location round to zero at the units shown.

Note: Totals of in-place volumes 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.

Summary of Best Estimate Prospective Gas Volumes by Location
As of December 31, 2021

Loc No.	Line-SP	OGIP (Bcf)	Unrisked Gross (100%) Recoverable (Bcf)	Effective P_g [1] (Decimal)	P_d (Decimal)	Risked Gross (100%) Recoverable (Bcf)
5	L01-16800	153.5	99.8	0.04	0.40	1.6
6	L01-19300	528.7	343.7	0.04	0.75	10.3
7	L01-22300	408.2	265.3	0.04	0.75	8.0
16	L05-23750	185.8	120.8	0.04	0.60	2.9
26	L10-4100	197.6	128.5	0.04	0.60	3.1
27	L10-6000	123.3	80.2	0.04	0.20	0.6
28	L10-8900	104.1	67.6	0.04	0.20	0.5
29	L10-12500	176.5	114.7	0.04	0.40	1.8
31	L01-24650	188.0	122.2	0.04	0.60	2.9
32	L10-15050	123.4	80.2	0.04	0.20	0.6
Total		**2,189.1**	**1,422.9**			**32.4**

[1] Effective probability of geologic success is the volume-weighted average of multiple probabilities

Note: Totals of in-place volumes 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.