DeGolyer and MacNaughton
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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 3, 2022

Eni S.p.A.
Andrea Giaccardo
Head of Reserves Department
Via Emilia 1
20097 San Donato Milanese
Milano, Italy

Dear Mr. Giaccardo:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2021, of the net proved oil, condensate, liquefied petroleum gas (LPG), and gas reserves of certain properties in Africa, America, Australia and Oceania, and Europe in which Eni S.p.A. (Eni) has represented it holds an interest. This evaluation was completed on March 3, 2022. Eni has represented that these properties account for 17 percent, on a net equivalent barrel basis, of Eni's net proved reserves as of December 31, 2021, and that Eni's net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). It is our opinion that the procedures and methodologies employed by Eni for the preparation of its proved reserves estimates as of December 31, 2021, comply with the current requirements of the SEC. We have reviewed information provided to us by Eni that it represents to be Eni's estimates of the net reserves, as of December 31, 2021, for the same properties as those which we have independently evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Eni.

Reserves estimates included herein are expressed as net reserves as represented by Eni. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Eni after deducting all interests held by others.

Estimates of reserves should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Eni. In the preparation of this report we have relied, without independent verification, upon information furnished by Eni with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves estimated in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by us in this report are in accordance with the reserves definitions of Rules 4–10(a)(1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

> *Proved oil and gas reserves* – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or

probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be

determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective

> by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, the development plans provided by Eni, and analyses of areas offsetting existing wells, reserves were classified as proved.

Eni has represented that its senior management is committed to the development plan provided by Eni and that Eni has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

Where applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material-balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or to the limit of production licenses as appropriate.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Data provided by Eni from wells drilled through December 31, 2021, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available only through June 30, 2021, for certain properties and as late as October 31, 2021, for other properties. Estimated cumulative production, as of December 31, 2021, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 6 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. LPG reserves estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG reserves included in this report are expressed in millions of barrels (10^6bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil, condensate, and LPG reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as marketable gas. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of the nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Gas reserves estimated herein are reported as marketable gas reserves. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit

(°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in billions of cubic feet ($10^9 ft^3$).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas includes both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein consist of both associated and nonassociated gas.

At the request of Eni, marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,310 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by Eni in United States dollars (U.S.$). Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the reserves reported herein:

Oil, Condensate, and LPG Prices

> Eni has represented that the oil, condensate, and LPG prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The Brent marker price for the period was U.S.$69.23 per barrel. Where appropriate, Eni supplied differentials by field to the relevant reference price and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties are presented below, expressed in United States dollars per barrel (U.S.$/bbl):

	Oil Price (U.S.$/bbl)	Condensate Price (U.S.$/bbl)	LPG Price (U.S.$/bbl)
Africa	68.87	63.05	40.90
America	NA	67.73	NA
Australia and Oceania	NA	60.74	NA
Europe	68.08	52.48	52.48

NA = Not Applicable

Gas Prices

Eni has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. A significant quantity of the gas sold by Eni is subject to a range of contract prices. The United Kingdom National Balancing Point Index reference price for the period was U.S.$14.75 per thousand cubic feet. Where appropriate, Eni supplied differentials by field to the relevant reference price and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties are presented below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3ft^3$):

	Gas Price (U.S.$/$10^3ft^3$)
Africa	3.11
America	4.32
Australia and Oceania	2.86
Europe	13.47

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Eni, were used in estimating future costs required to operate the properties. In certain cases, future costs, either higher or lower than existing costs, may have been used because of anticipated changes in operating conditions. These costs were not escalated for inflation.

In our opinion, the information relating to estimated proved reserves of oil, condensate, LPG, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, and 932-235-50-9 of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, and 1202(a) (1), (2), (3), (4), (8) of Regulation S–K of the SEC; provided, however, that estimates of proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

Eni has represented that its estimated net proved reserves attributable to the evaluated properties in Africa, America, Australia and Oceania, and Europe were based on the definitions of proved reserves of the SEC. Eni has represented that its estimates of the net proved reserves, as of December 31, 2021, attributable to these properties, which represent 17 percent of Eni's net reserves on a net equivalent basis, are summarized as follows, expressed in millions of barrels (10^6bbl), billions of cubic feet (10^9ft^3), and millions of barrels of oil equivalent (10^6boe):

	Estimated by Eni Net Proved Reserves as of December 31, 2021		
	Oil, Condensate, and LPG (10^6bbl)	**Marketable Gas (10^9ft^3)**	**Oil Equivalent (10^6boe)**
Properties evaluated by DeGolyer and MacNaughton			
Africa	236	426	317
America	7	1,460	282
Australia and Oceania	1	427	82
Europe	360	581	469
Total Proved	**604**	**2,894**	**1,150**

Note: Marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,310 cubic feet of gas per 1 barrel of oil equivalent.

In comparing the detailed net proved reserves estimates prepared by DeGolyer and MacNaughton and by Eni, differences have been found, both positive and negative, resulting in an aggregate difference of less than 5 percent when compared on the basis of net equivalent barrels. It is DeGolyer and MacNaughton's opinion that the net proved reserves estimates prepared by Eni on the properties evaluated and referred to above, when compared on the basis of net equivalent barrels, do not differ materially from those estimated by DeGolyer and MacNaughton.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2021, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Eni. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Eni. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

CERTIFICATE of QUALIFICATION

I, Regnald A. Boles, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare the report of third party addressed to Eni dated March 3, 2022, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 1983; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; that I am a member of the European Association of Geoscientists and Engineers; and that I have in excess of 38 years of experience in oil and gas reservoir studies and evaluations.

SIGNED: March 3, 2022

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton