UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

Form 20-F

(Mark One)

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) or (g) OF THE SECURITIES EXCHANGE ACT OF 1934

OR

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2018

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______________ to ______________

OR

☐ SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Date of event requiring this shell company report

Commission file number: 1-14090

Eni SpA

(Exact name of Registrant as specified in its charter)

Republic of Italy
(Jurisdiction of incorporation or organization)

1, piazzale Enrico Mattei - 00144 Roma - Italy
(Address of principal executive offices)

Massimo Mondazzi
Eni SpA
1, piazza Ezio Vanoni
20097 San Donato Milanese (Milano) - Italy
Tel +39 02 52041730 - Fax +39 02 52041765
(Name, Telephone, Email and/or Facsimile number and Address of Company Contact Person)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Shares	**New York Stock Exchange***
American Depositary Shares	**New York Stock Exchange**
(Which represent the right to receive two Shares)	* Not for trading, but only in connection with the registration of American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission.

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

Ordinary shares **3,634,185,330**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☑ No ☐

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ☐ No ☑

Note - Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 from their obligations under those Sections.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

U.S. GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question, indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐ Item 18 ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☑

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Certain disclosures contained herein including, without limitation, certain information appearing in "Item 4 – Information on the Company", and in particular "Item 4 – Exploration & Production", "Item 5 – Operating and Financial Review and Prospects" and "Item 11 – Quantitative and Qualitative Disclosures about Market Risk" contain forward-looking statements regarding future events and the future results of Eni that are based on current expectations, estimates, forecasts, and projections about the industries in which Eni operates and the beliefs and assumptions of the management of Eni. Eni may also make forward-looking statements in other written materials, including other documents filed with or furnished to the U.S. Securities and Exchange Commission (the "SEC"). In addition, Eni's senior management may make forward-looking statements orally to analysts, investors, representatives of the media and others. In particular, among other statements, certain statements with regard to management objectives, trends in results of operations, margins, costs, return on capital, risk management and competition are forward looking in nature. Words such as 'expects', 'anticipates', 'targets', 'goals', 'projects', 'intends', 'plans', 'believes', 'seeks', 'estimates', variations of such words, and similar expressions are intended to identify such forward-looking statements. These forward-looking statements are only predictions and are subject to risks, uncertainties, and assumptions that are difficult to predict because they relate to events and depend on circumstances that will occur in the future. Therefore, Eni's actual results may differ materially and adversely from those expressed or implied in any forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in this Annual Report on Form 20-F under the section entitled "Risk factors" and elsewhere. Any forward-looking statements made by or on behalf of Eni speak only as of the date they are made. Eni does not undertake to update forward-looking statements to reflect any changes in Eni's expectations with regard thereto or any changes in events, conditions or circumstances on which any such statement is based. The reader should, however, consult any further disclosures Eni may make in documents it files with the SEC.

CERTAIN DEFINED TERMS

In this Form 20-F, the terms "Eni", the "Group", or the "Company" refer to the parent company Eni SpA and its consolidated subsidiaries and, unless the context otherwise requires, their respective predecessor companies. All references to "Italy" or the "State" are references to the Republic of Italy, all references to the "Government" are references to the government of the Republic of Italy. For definitions of certain oil and gas terms used herein and certain conversions, see "Glossary" and "Conversion Table".

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

The Consolidated Financial Statements of Eni, included in this Annual Report, have been prepared in accordance with International Financial Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Unless otherwise indicated, any reference herein to "Consolidated Financial Statements" is to the Consolidated Financial Statements of Eni (including the Notes thereto) included herein.

Unless otherwise specified or the context otherwise requires, references herein to "dollars", "$", "U.S. dollars", "US$" and "USD" are to the currency of the United States, and references to "euro", "EUR" and "€" are to the currency of the European Monetary Union.

Unless otherwise specified or the context otherwise requires, references herein to "Division" and "segment" are to any of the following Eni's business activities: Exploration & Production, Gas & Power, Refining & Marketing and Chemicals, Corporate and Other activities.

References to Versalis or Chemical are to Eni's chemical activities which are managed through its fully-owned subsidiary Versalis and Versalis' controlled entities.

STATEMENTS REGARDING COMPETITIVE POSITION

Statements made in "Item 4 – Information on the Company" referring to Eni's competitive position are based on the Company's belief, and in some cases rely on a range of sources, including investment analysts' reports, independent market studies and Eni's internal assessment of market share based on publicly available information about the financial results and performance of market participants. Market share estimates contained in this document are based on management estimates unless otherwise indicated.

GLOSSARY

A glossary of oil and gas terms is available on Eni's web page at the address eni.com. Below is a selection of the most frequently used terms. Any reference herein to a non-GAAP measure and to its most directly comparable GAAP measure shall be intended as a reference to a non-IFRS measure and the comparable IFRS measure.

Financial terms

Leverage	A non-GAAP measure of the Company's financial condition, calculated as the ratio between net borrowings and shareholders' equity, including non-controlling interest. For a discussion of management's view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure, "Ratio of total debt to total shareholders's equity (including non-controlling interest)" see "Item 5 – Financial Condition".
Net borrowings	Eni evaluates its financial condition by reference to "net borrowings", which is a non-GAAP measure. Eni calculates net borrowings as total finance debt less: cash, cash equivalents and certain very liquid investments not related to operations, including among others non-operating financing receivables and securities not related to operations. Non-operating financing receivables consist of amounts due to Eni's financing subsidiaries from banks and other financing institutions and amounts due to other subsidiaries from banks for investing purposes and deposits in escrow. Securities not related to operations consist primarily of government and corporate securities. For a discussion of management's view of the usefulness of this measure and its reconciliation with the most directly comparable GAAP measure, "Total debt" see "Item 5 – Financial condition".
TSR (Total Shareholder Return)	Management uses this measure to asses the total return on Eni's shares. It is calculated on a yearly basis, keeping account of the change in market price of Eni's shares (at the beginning and at end of year) and dividends distributed and reinvested at the ex-dividend date.

Business terms

ARERA (Italian Regulatory Authority for Energy, Networks and Environment) formerly AEEGSI (Authority for Electricity Gas and Water)	The Italian Regulatory Authority for Energy, Networks and Environment is the Italian independent body which regulates, controls and monitors the electricity, gas and water sectors and markets in Italy. The Authority's role and purpose is to protect the interests of users and consumers, promote competition and ensure efficient, cost-effective and profitable nationwide services with satisfactory quality levels. Furthermore, since December 2017 the Authority has also regulatory and control functions over the waste cycle, including sorted, urban and related waste.
Associated gas	Associated gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Average reserve life index	Ratio between the amount of reserves at the end of the year and total production for the year.
Barrel/BBL	Volume unit corresponding to 159 liters. A barrel of oil corresponds to about 0.137 metric tons.
BOE	Barrel of Oil Equivalent. It is used as a standard unit measure for oil and natural gas. The latter is converted from standard cubic meters into barrels of oil equivalent using a certain coefficient (see "Conversion Table").
Concession contracts	Contracts currently applied mainly in Western countries regulating relationships between states and oil companies with regards to hydrocarbon exploration and production. The company holding the mining concession has an exclusive right on exploration, development and production activities and for this reason it acquires a right to hydrocarbons extracted against the payment of royalties on production and taxes on oil revenues to the state.
Condensates	Condensates is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.
Consob	The Italian National Commission for listed companies and the stock exchange.

Contingent resources	Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.
Conversion capacity	Maximum amount of feedstock that can be processed in certain dedicated facilities of a refinery to obtain finished products. Conversion facilities include catalytic crackers, hydrocrackers, visbreaking units, and coking units.
Conversion index	Ratio of capacity of conversion facilities to primary distillation capacity. The higher the ratio, the higher is the capacity of a refinery to obtain high value products from the heavy residue of primary distillation.
Deep waters	Waters deeper than 200 meters.
Development	Drilling and other post-exploration activities aimed at the production of oil and gas.
Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
EPCI	Engineering, Procurement, Construction and Installation.
Exploration	Oil and natural gas exploration that includes land surveys, geological and geophysical studies, seismic data gathering and analysis and well drilling.
FPSO	Floating Production Storage and Offloading System.
FSO	Floating Storage and Offloading System.
Infilling wells	Infilling wells are wells drilled in a producing area in order to improve the recovery of hydrocarbons from the field and to maintain and/or increase production levels.
LNG	Liquefied Natural Gas obtained through the cooling of natural gas to minus 160 °C at normal pressure. The gas is liquefied to allow transportation from the place of extraction to the sites at which it is transformed back into its natural gaseous state and consumed. One tonne of LNG corresponds to 1,400 cubic meters of gas.
LPG	Liquefied Petroleum Gas, a mix of light petroleum fractions, gaseous at normal pressure and easily liquefied at room temperature through limited compression.
Margin	The difference between the average selling price and direct acquisition cost of a finished product or raw material excluding other production costs (e.g. refining margin, margin on distribution of natural gas and petroleum products or margin of petrochemical products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.
Mineral Potential	(Potentially recoverable hydrocarbon volumes) Estimated recoverable volumes which cannot be defined as reserves due to a number of reasons, such as the temporary lack of viable markets, a possible commercial recovery dependent on the development of new technologies, or for their location in accumulations yet to be developed or where evaluation of known accumulations is still at an early stage.
Mineral Storage	According to Legislative Decree No. 164/2000, these are volumes required for allowing optimal operation of natural gas fields in Italy for technical and economic reasons. The purpose is to ensure production flexibility as required by long-term purchase contracts as well as to cover technical risks associated with production.
Modulation Storage	According to Legislative Decree No. 164/2000, these are volumes required for meeting hourly, daily and seasonal swings in demand.
Natural gas liquids (NGL)	Liquid or liquefied hydrocarbons recovered from natural gas through separation equipment or natural gas treatment plants. Propane, normal-butane and isobutane, isopentane and pentane plus, that were previously defined as natural gasoline, are natural gas liquids.
Network Code	A code containing norms and regulations for access to, management and operation of natural gas pipelines.

Over/Under lifting	Agreements stipulated between partners which regulate the right of each to its share in the production for a set period of time. Amounts lifted by a partner different from the agreed amounts determine temporary Over/Under lifting situations.
Possible reserves	Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
Probable reserves	Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Primary balanced refining capacity	Maximum amount of feedstock that can be processed in a refinery to obtain finished products measured in BBL/d.
Production Sharing Agreement (PSA)	Contract regulates relationships between states and oil companies with regard to the exploration and production of hydrocarbons. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract the national oil company assigns to the international contractor the task of performing exploration and production with the contractor's equipment and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "Cost Oil" is used to recover costs borne by the contractor and "Profit Oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country.
Proved 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. 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. Reserves are classified as either developed and undeveloped. Proved developed oil and gas reserves are reserves that can be expected to be recovered 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 through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved 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.
Reserves	Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reserve life index	Ratio between the amount of proved reserves at the end of the year and total production for the year.

Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company's ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves – in PSAs – due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.
Take-or-pay	Clause included in natural gas supply contracts according to which the purchaser is bound to pay the contractual price or a fraction of such price for a minimum quantity of gas set in the contract whether or not the gas is collected by the purchaser. The purchaser has the option of collecting the gas paid for and not delivered at a price equal to the residual fraction of the price set in the contract in subsequent contract years.
Title Transfer Facility	The Title Transfer Facility, more commonly known as TTF, is a virtual trading point for natural gas in the Netherlands. TTF Price is quoted in euro per megawatt hour and, for business day, is quoted day-ahead, i.e. delivered next working day after assessment.
Upstream/Downstream	The term upstream refers to all hydrocarbon exploration and production activities. The term downstream includes all activities inherent to the oil and gas sector that are downstream of exploration and production activities.

ABBREVIATIONS

mmCF	= million cubic feet
BCF	= billion cubic feet
mmCM	= million cubic meters
BCM	= billion cubic meters
BOE	= barrel of oil equivalent
KBOE	= thousand barrel of oil equivalent
mmBOE	= million barrel of oil equivalent
BBOE	= billion barrel of oil equivalent
BBL	= barrel
KBBL	= thousand barrels
mmBBL	= million barrels
BBBL	= billion barrels
ktonnes	= thousand tonnes
mmtonnes	= million tonnes
MW	= megawatt
GWh	= gigawatthour
TWh	= terawatthour
/d	= per day
/y	= per year
E&P	= the Exploration & Production segment
G&P	= the Gas & Power segment
R&M & C	= the Refining & Marketing and Chemicals segment
E&C	= the Engineering & Construction segment

CONVERSION TABLE

1 acre	= 0.405 hectares	
1 barrel	= 42 U.S. gallons	
1 BOE	= barrel of crude oil	= 5,458 cubic feet of natural gas
1 barrel of crude oil per day	= approximately 50 tonnes of crude oil per year	
1 cubic meter of natural gas	= 35.3147 cubic feet of natural gas	
1 cubic meter of natural gas	= approximately 0.00647 barrels of oil equivalent	
1 kilometer	= approximately 0.62 miles	
1 short ton	= 0.907 tonnes	= 2,000 pounds
1 long ton	= 1.016 tonnes	= 2,240 pounds
1 tonne	= 1 metric ton	= 1,000 kilograms = approximately 2,205 pounds
1 tonne of crude oil	= 1 metric ton of crude oil	= approximately 7.3 barrels of crude oil (assuming an API gravity of 34 degrees)

PART I

Item 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISORS

NOT APPLICABLE

Item 2. OFFER STATISTICS AND EXPECTED TIMETABLE

NOT APPLICABLE

Item 3. KEY INFORMATION

Selected Financial Information

The Consolidated Financial Statements of Eni have been prepared in accordance with IFRS as issued by the International Accounting Standards Board (IASB). The tables below present Eni selected historical financial data prepared in accordance with IFRS as of and for the years ended December 31, 2014, 2015, 2016, 2017 and 2018. Eni has adopted IFRS 9 'Financial Instruments' and IFRS 15 'Revenue from Contracts with Customers' with effect from 1 January 2018. Information on the implementation of new accounting standards is included in the Financial statements – Note 3 Changes in accounting policies. As permitted by IFRS 9 comparatives have not been restated; while with regard to IFRS 16, Eni has elected to apply the 'modified retrospective' approach to transition permitted by IFRS 15 under which comparative financial information is not restated. The adoption of the new standards did not have a material effect on the group's financial statements as at January 1, 2018. In 2015, the business segment Engineering & Construction (E&C), operated by Eni's former subsidiary Saipem, was classified as discontinued operations based on the guidelines of IFRS 5. On January 26, 2016 Eni divested part of its interest in Saipem; this transaction triggered the loss of control on the former subsidiary. The retained interest in Saipem (31%) was classified as an investment in a joint venture, accounted for under the equity method. Also in the financial data for 2014 the E&C segment is presented as discontinued operations. All such data should be read in connection with the Consolidated Financial Statements and the related notes thereto included in Item 18.

	Year ended December 31,				
	2018	2017	2016	2015	2014
	(€ million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	75,822	66,919	55,762	72,286	98,218
Operating profit (loss) by segment from continuing operations					
Exploration & Production	10,214	7,651	2,567	(959)	10,727
Gas & Power	629	75	(391)	(1,258)	64
Refining & Marketing and Chemicals	(380)	981	723	(1,567)	(2,811)
Corporate and Other activities	(691)	(668)	(681)	(497)	(518)
Impact of unrealized intragroup profit elimination and other consolidation adjustments(1)	211	(27)	(61)	1,205	1,503
Operating profit (loss) from continuing operations	9,983	8,012	2,157	(3,076)	8,965
Net profit (loss) attributable to Eni from continuing operations	4,126	3,374	(1,051)	(7,952)	1,720
Net profit (loss) attributable to Eni from discontinued operations			(413)	(826)	(413)
Net profit (loss) attributable to Eni	4,126	3,374	(1,464)	(8,778)	1,307
Data per ordinary share (euro)(2)					
Operating profit (loss):					
– basic	2.77	2.22	0.60	(0.85)	2.48
– diluted	2.77	2.22	0.60	(0.85)	2.48
Net profit (loss) attributable to Eni basic and diluted from continuing operations	1.15	0.94	(0.29)	(2.21)	0.48
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	0.00	(0.12)	(0.23)	(0.12)
Net profit (loss) attributable to Eni basic and diluted	1.15	0.94	(0.41)	(2.44)	0.36
Data per ADR ($)(2)(3)					
Operating profit (loss):					
– basic	6.55	5.03	1.33	(1.90)	6.59
– diluted	6.55	5.03	1.33	(1.90)	6.59
Net profit (loss) attributable to Eni basic and diluted from continuing operations	2.72	2.12	(0.65)	(4.90)	1.27
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.00	0.00	(0.25)	(0.51)	(0.31)
Net profit (loss) attributable to Eni basic and diluted	2.72	2.12	(0.90)	(5.41)	0.96

(1) This item pertains to intragroup sales of commodities and capital goods recorded in the assets of the purchasing business segment as of the end of the reporting period.

(2) Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2018 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on May 14, 2019.

(3) Eni's financial statements are stated in euro. The translations of certain euro amounts into U.S. dollars are included solely for the convenience of the reader. The convenient translations should not be construed as representations that the amounts in euro have been, could have been, or could in the future be, converted into U.S. dollars at this or any other rate of exchange. Data per ADR, with the exception of dividends, were translated at the EUR/U.S.$ average exchange rate as recorded by in the Federal Reserve Board official statistics for each year presented (see the table on page 5). Dividends per ADR for the years 2014 through 2017 were translated into U.S. dollars for each year presented using the Noon Buying Rate on payment dates, as recorded on the payment date of the interim dividend and of the balance to the full-year dividend, respectively. The dividend for 2018 based on the management's proposal to the General Shareholders' Meeting and subject to approval was translated as per the portion related to the interim dividend (€0.84 per ADR) at the Noon Buying Rate recorded on the payment date on September 26, 2018, while the balance of €0.82 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2018. The balance dividend for 2018 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on May 22, 2019 to holders of Eni shares, being the ex-dividend date May 20, 2019 while ADRs holders will be paid on June 06, 2019.

	As of December 31,				
	2018	2017	2016	2015	2014
	(€ million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	118,373	114,928	124,545	139,001	150,366
Short-term and long-term debt	25,865	24,707	27,239	27,793	25,891
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Non-controlling interest	57	49	49	1,916	2,455
Shareholders' equity – Eni share	51,016	48,030	53,037	55,493	63,186
Capital expenditures from continuing operations	9,119	8,681	9,180	10,741	11,178
Weighted average number of ordinary shares outstanding (fully diluted – shares million)	3,601	3,601	3,601	3,601	3,610
Dividend per share (euro)(1)	0.83	0.80	0.80	0.80	1.12
Dividend per ADR ($)(1)(2)	1.96	1.81	1.77	1.77	2.65

(1) Euro per share or U.S. dollars per American Depositary Receipt (ADR), as the case may be. One ADR represents two Eni shares. The dividend amount for 2018 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on May 14, 2019.

(2) Eni's financial statements are stated in euro. The translations of certain euro amounts into U.S. dollars are included solely for the convenience of the reader. The convenient translations should not be construed as representations that the amounts in euro have been, could have been, or could in the future be, converted into U.S. dollars at this or any other rate of exchange. Data per ADR, with the exception of dividends, were translated at the EUR/U.S.$ average exchange rate as recorded by in the Federal Reserve Board official statistics for each year presented (see the table on page 5). Dividends per ADR for the years 2013 through 2017 were translated into U.S. dollars for each year presented using the Noon Buying Rate on payment dates, as recorded on the payment date of the interim dividend and of the balance to the full-year dividend, respectively. The dividend for 2018 based on the management's proposal to the General Shareholders' Meeting and subject to approval was translated as per the portion related to the interim dividend (€0.84 per ADR) at the Noon Buying Rate recorded on the payment date on September 26, 2018, while the balance of €0.82 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2018. The balance dividend for 2018 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on May 22, 2019 to holders of Eni shares, being the ex-dividend date May 20, 2019 while ADRs holders will be paid on June 06, 2019

Selected Operating Information

The tables below set forth selected operating information with respect to Eni's proved reserves, developed and undeveloped, of crude oil (including condensates and natural gas liquids) and natural gas, as well as other data as of and for the years ended December 31, 2014, 2015, 2016, 2017 and 2018.

	Year ended December 31,				
	2018	2017	2016	2015	2014
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,183	3,262	3,230	3,372	3,077
of which developed	*2,208*	*2,220*	*2,190*	*2,100*	*1,847*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	357	160	168	187	149
of which developed	*205*	*43*	*43*	*48*	*46*
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	17,324	17,290	18,462	14,302	14,808
of which developed	*11,203*	*9,535*	*9,244*	*8,899*	*8,342*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	2,400	2,182	3,871	3,993	3,737
of which developed	*2,063*	*1,916*	*1,905*	*1,402*	*120*
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end	6,356	6,430	6,613	5,975	5,772
of which developed	*4,261*	*3,967*	*3,884*	*3,720*	*3,366*
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end	797	560	877	915	830
of which developed	*583*	*394*	*391*	*303*	*67*
Average daily production of liquids (KBBL/d)(1)	884	852	878	908	828
Average daily production of natural gas available for sale (mmCF/d)(1)	4,630	4,734	4,329	4,284	3,782
Average daily production of hydrocarbons available for sale (KBOE/d)(1)	1,732	1,719	1,671	1,688	1,517
Hydrocarbon production sold (mmBOE)	625.0	622.3	608.6	614.1	549.5
Oil and gas production costs per BOE(2)	6.50	6.33	5.90	9.18	12.00
Profit per barrel of oil equivalent(3)	9.27	8.72	1.98	(3.83)	9.86

(1) Referred to Eni's subsidiaries and its equity-accounted entities. It excludes production volumes of hydrocarbon consumed in operation (119, 97, 88, 73 and 81 KBOE/d in 2018, 2017, 2016, 2015 and 2014 respectively).

(2) Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment) prepared in accordance with IFRS divided by production on an available-for-sale basis, expressed in barrels of oil equivalent. See the unaudited supplemental oil and gas information in "Item 18 – Notes to the Consolidated Financial Statements". With effect from January 1, 2018, with a view to conforming to customary industry practice, Eni has changed the method for calculating the average production cost per barrel-of-oil equivalent. Oil and gas production costs per BOE for prior periods have been recomputed in the table above for comparability. Average production costs no longer include the following items which have previously been included: (i) Royalties and other production taxes; and (ii) Transportation costs relating to the export of the saleable volumes of oil and gas produced, other than the costs incurred to deliver hydrocarbons to a main pipeline, a common carrier, a refinery or a maritime terminal, when unusual physical or operational circumstances exist. If calculated under the previous method, the average production cost for the year 2018 would be $9.33 per boe. Production costs per boe for the comparative periods 2017 and 2016 as previously published and calculated under the previous method were $8.45 and $7.79 respectively. A full reconciliation between recomputed average production costs and originally-published amounts is provided in Item 4 in the "Oil and gas production, production prices and production costs" paragraph of the Exploration & Production section. Prior year data have not been recomputed.

(3) Expressed in U.S. dollars. Results of operations from oil and gas producing activities of consolidated subsidiaries, divided by actual sold production, in each case prepared in accordance with IFRS to meet ongoing U.S. reporting obligations under Topic 932. See the unaudited supplemental oil and gas information in "Item 18 – Notes to the Consolidated Financial Statements" for a calculation of results of operations from oil and gas producing activities.

Selected Operating Information *continued*

	Year ended December 31,				
	2018	2017	2016	2015	2014
Worldwide natural gas sales(1)	76.71	80.83	86.31	87.72	86.11
Electricity sold(2)	37.07	35.33	37.05	34.88	33.58
Refinery throughputs(3)	23.23	24.02	24.52	26.41	25.03
Balanced capacity of wholly-owned refineries(4)	388	388	388	388	404
Retail sales (in Italy and rest of Europe)(3)	8.39	8.54	8.59	8.89	9.21
Number of service stations at period end (in Italy and rest of Europe)	5,448	5,544	5,622	5,846	6,220
Chemical production(3)	9.48	8.96	8.81	8.67	7.93
Average throughput per service station (in Italy and rest of Europe)(5)	1,776	1,783	1,742	1,754	1,725
Employees at period end (number)	31,701	32,934	33,536	34,196	34,846

(1) Expressed in BCM.
(2) Expressed in TWh.
(3) Expressed in mmtonnes.
(4) Expressed in KBBL/d.
(5) Expressed in thousand liters per day.

Risk factors

The risks described below may have a material effect on our operational and financial performance. We invite our investors to consider these risks carefully.

Eni's operating results, cash flow and rates of growth are affected by volatile prices of crude oil, natural gas, oil products and chemicals

Prices of oil and natural gas have a history of volatility due to many factors that are beyond Eni's control. These factors include among other things:

- global and regional dynamics of oil and gas supply and demand and global level of inventories. In 2018, the oil market environment was a volatile one. Until October 2018, crude oil prices continued the upward trend commenced in the second half of 2017 driven by economic growth, effectiveness of the production cuts implemented by OPEC Countries and other producers agreed at the end of November 2016 and normalizing inventory level. Geopolitical risks also played a role including production disruption in Venezuela, renewed internal tensions in Libya and worsening relations between USA and Iran. Oil prices peaked in October 2018, touching a four-year high around 85 $/BBL for the Brent crude oil benchmark. Then in November 2018, a sharp downturn, one of the steepest on record, followed driving crude oil prices as low as 60 $/BBL, a correction of about 30%. This downturn was driven by emerging trends pointing to an economic slowdown, uncertainties relating to the developments of the USA-China trade dispute and of the Brexit, and building oversupplies due to rising production levels in USA, OPEC and Russia also in anticipation of the enactment of US sanctions against Iran, which would happen to be less severe than expected. In December 2018, OPEC and Russia agreed to cut again production quotas by 1.2 million bbl/d, effective from January 2019, in an effort to curb a supply glut. In spite of this development, crude oil prices continued to slide throughout December 2018 to the year's lows of 50 $/bbl, extending the correction from the highs to 40%. On average, in 2018 the price for the Brent crude oil benchmark increased by 31% y-o-y at about 71 $/BBL.
  In early 2019, oil prices regained the sixty-dollar mark thanks to better-than-expected gauges of economic activity and implementation of the production cuts. In the first quarter of 2019, the Brent crude oil price averaged approximately 63 $/BBL pointing to renewed strength;
- global political developments, including sanctions imposed on certain producing countries and conflict situations;
- global economic and financial market conditions;
- the ability of the OPEC cartel to control world supply and therefore oil prices;

- prices and availability of alternative sources of energy (e.g., nuclear, coal and renewables);
- weather conditions;
- operational issues;
- governmental regulations and actions;
- success in the development and deployment of new technologies for the recovery of crude oil and natural gas reserves and technological advances affecting energy consumption;
- competition from alternative energy sources like solar energy, photovoltaic and other renewables;
- rising commitment of the world nations and the civil society to addressing the issue of global warming and climate change by reducing the release in the atmosphere of greenhouse gases ("GHG") produced by the consumption of hydrocarbons in human activities.

All these factors can affect the global balance between demand and supply for hydrocarbons and hence prices of crude oil, natural gas, and other energy commodities.

Management expects global oil demand to grow by approximately 1.4 mmBBL/d in 2019, more or less in line with 2018, and global oil demand and supplies to be balanced overall. Considering the risks of an economic slowdown, geopolitical factors, uncertainties associated with possible developments in the USA-China trade dispute and with the Brexit, management is assuming a Brent price of 62 $/BBL in 2019, gradually increasing over the following three year period to reach 70$/BBL in 2022. After 2022, management is assuming a price growing in line with inflation (e.g. 71.4 $/BBL in 2023 assuming a long-term inflationary rate of 2%) based on its view of market fundamentals and oil price projections made by specialized agencies and financial analysts, substantially in line with the previous planning assumptions. Management's oil price forecast was utilized to elaborate the Group financial projections and the level of Group's capital expenditures for the 2019 – 2022 industrial plan and to estimate recoverability of the carrying amounts of the Group's oil and gas assets as of December 31, 2018.

Fluctuations in oil and natural gas prices materially affect the Group's results of operations and business prospects. Lower prices from one year to another negatively affect the Group's consolidated results of operations and cash flow. This is because lower prices translate into lower revenues recognized in the Company's Exploration & Production segment at the time of the price change, whereas expenses in this segment are either fixed or less sensitive to changes in crude oil prices than revenues. Based on the current portfolio of oil and gas assets, Eni's management estimates that the Company's consolidated net cash provided by operating activities would vary by approximately €190 million for each one-dollar change in the price of the Brent crude oil benchmark with respect to the price case assumed in Eni's financial projections for 2019 at 62 $/BBL. Furthermore, a structural decline in commodity prices may have material effects on Eni's business outlook and may limit the Group's funds available to finance expansion projects and certain contractual commitments. This because lower oil and gas prices over prolonged periods may adversely affect the funds available to finance expansion projects, further reducing the Company's ability to grow future production and revenues. In addition, in a weak scenario the Company may also need to review investment decisions and the viability of development projects and capex plans and as a result of this review the Company could reschedule, postpone or curtail development projects.

In case of a structural decline in hydrocarbon prices, the Company may review the carrying amounts of oil and gas properties and this could result in recording material asset impairments. Finally, lower oil and gas prices could result in the de-booking of proved reserves, if they become uneconomic in this type of environment. These risks may adversely impact the Group's results of operations, cash flow, liquidity, business prospects and shareholder returns, including dividends and the share prices.

In response to weakened oil and gas industry conditions and resulting revisions made to rating agency commodity price assumptions, lower commodity prices may also reduce the Group's access to capital and lead to a downgrade or other negative rating action with respect to the Group's credit rating by rating agencies, including Standard & Poor's Ratings Services ("S&P") and Moody's Investor Services Inc ("Moody's"). These downgrades may negatively affect the Group's cost of capital, increase the Group's financial expenses, and may limit the Group's ability to access capital markets and execute aspects of the Group's business plans.

Eni is estimating that approximately 50 per cent of its current production is exposed to fluctuations in hydrocarbons prices. Exposure to this strategic risk is not subject to economic hedging, except for some specific market conditions or transactions. The remaining portion of Eni's current production is largely unaffected by crude oil price movements considering that the Company's property portfolio is characterized by a sizeable presence of production sharing contracts, whereby, due to the cost recovery mechanism, the Company is entitled to a larger number of barrels in the event of a fall in crude oil prices. (See the specific risks of the Exploration & Production segment in "*Risks associated with the exploration and production of oil and natural gas*" below).

The Group's results from its Refining & Marketing and Chemicals businesses are primarily dependent upon the supply and demand for refined and chemical products and the associated margins on refined products and chemical products sales, with the impact of changes in oil prices on results of these segments being dependent upon the speed at which the prices of products adjust to reflect movements in oil prices.

Because of the above mentioned risks, a prolonged decline in commodity prices would materially and adversely affect the Group's business prospects, financial condition, results of operations, cash flows, ability to finance planned capital expenditures and commitments and may impact shareholder returns, including dividends and the share price.

Competition

There is strong competition worldwide, both within the oil industry and with other industries, to supply energy and petroleum products to the industrial, commercial and residential energy markets

Eni faces strong competition in each of its business segments.

The current competitive environment in which Eni operates is characterized by volatile prices and margins of energy commodities, limited product differentiation and complex relationships with state-owned companies and national agencies of the countries where hydrocarbons reserves are located to obtain mineral rights. As commodity prices are beyond the Company's control, Eni's ability to remain competitive and profitable in this environment requires continuous focus on technological innovation, the achievement of efficiencies in operating cost, efficient management of capital resources and the ability to provide valuable services to the energy buyers. It also depends on Eni's ability to gain access to new investment opportunities, both in Europe and worldwide.

- In the Exploration & Production segment, Eni faces competition from both international and state-owned oil companies for obtaining exploration and development rights, and developing and applying new technologies to maximize hydrocarbon recovery. Furthermore, Eni may face a competitive disadvantage because of its smaller size relative to other international oil companies, particularly when bidding for large scale or capital intensive projects, and it may be exposed to the risk of obtaining lower cost savings in a deflationary environment compared to its larger competitors given its potentially smaller market power with respect to suppliers. If, because of those competitive pressures, Eni fails to obtain new exploration and development acreage, to apply and develop new technologies, and to control costs, its growth prospects and future results of operations and cash flow in this business may be adversely affected.
- In the Gas & Power segment, Eni is facing strong competition in the European wholesale gas markets to sell gas to industrial customers, the thermoelectric sector and retailer companies from other gas wholesalers, upstream companies, traders and other players both in the Italian market and in markets across Europe. In recent years, competition has been fueled by muted demand growth, oversupplies and the development of very liquid European spot markets where large volumes of gas are traded daily. Players are competing mainly in terms of pricing and to a lesser extent on the ability to offer additional services to the buyers of the commodity, like volume flexibilities, different pricing options, the possibility to change the delivery point and other optionality. Management believes that competition in the European wholesale gas market will continue to negatively affect the results of operations and cash flow of Eni's Gas & Power segment in future reporting periods. Eni's Gas & Power segment also engages in the supply of gas and electricity to customers in the retail markets mainly in Italy, France and other areas in Europe. Customers include households, large residential accounts (hospitals, schools, public administration buildings, offices) and small and medium-sized businesses located in urban areas. The retail market is characterized by strong competition among local selling companies which mainly compete in term of pricing and the ability to bundle valuable services with the supply of the energy commodity. In this segment competition has intensified in recent years due to the

progressive liberalization of the market and the option on part of residential customers to switch smoothly from one supplier to another. Management believes that competition will represent a risk factor to the Company's results of operations and cash flow in this business unit.

- Eni is facing strong competitive pressure in its business of gas-fired electricity generation which is largely sold at wholesale markets in Italy. Margins on the sale of electricity have declined in recent years due to oversupplies, weak economic growth and inter-fuel competition. This latter was due to the fact that power produced from renewable sources and coal-fired power generation are cheaper than gas-fired electricity, although coal-fired plants are expected to be progressively phased-out due to environmental issues. Management believes that these negative factors will continue to negatively affect crack-spread margins on electricity at Italian wholesale markets and the profitability of this business unit in the foreseeable future.
- In the Refining & Marketing segment, Eni faces strong competition both in the wholesale markets and in the retail marketing activity. Margins of European refiners are facing structural headwinds due to muted trends in the European demand for fuels and continued competitive pressures from players in the Middle East, the USA and Asia, who can leverage on larger plant scale and cost economies, availability of cheaper feedstock, lower energy expenses and fewer environmental obligations. Eni believes that the competitive environment will remain challenging in the foreseeable future, also considering refining overcapacity in the European area and expectations of a new investment cycle driven by capacity expansion plans announced in Asia and the Middle East, potentially leading to a situation of global oversupplies of refinery products. In 2018 Eni's gauge of profitability in the refining business fell by approximately 26% to 3.7 $/BBL driven by rising costs of oil-based feedstock that the Company was unable to transfer to final products prices pressured by the weak market fundamentals described above. This decline negatively affected the performance of the Company's refining activity. Management believes that in the long-term the trading environment will not recover meaningfully with refining margins seen in a 4-5 $/BBL range. Furthermore, Eni's refining margins are exposed to the volatility in the spreads between crudes with high sulfur content or sour crudes vs. the Brent crude benchmark, which is a low-content sulfur crude. Eni complex refineries are able to process sour crudes which typically trade at a discount over the Brent crude. However, in 2019 a shortfall in supplies of sour crudes is expected in the market due to the production cuts implemented by OPEC, lower exports from Venezuela and the USA sanctions against Iran. Those developments could result in an appreciation of the relative prices of sour crudes vs. the Brent, which would negatively affect the results of our refining business. Against this backdrop, management has designed an action plan intended to reduce the Company's breakeven margin in its refining business to about 3 $/BBL in 2019 by means of plant and feedstock optimization, energy savings and other cost efficiencies. Additionally, management expects to close by year-end the acquisition of a 20%-stake in a large refining asset in Abu Dhabi, which will de-risk Eni's refining business due to the fact that the asset being acquired is more profitable than Eni's legacy refineries due to larger scale, efficiency, geographic reach and proximity to raw materials sources. In case management fails to execute on this plan, the profitability of Eni's refining business may be negatively affected considering management's expectations for a weak trading environment. In marketing, Eni faces competition from other oil companies and newcomers such as low-scale operators and large retailers, who tend to adopt aggressive pricing policies. All these operators compete with each other primarily in terms of pricing and, to a lesser extent, service quality.
- In the Chemicals business, Eni faces strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized market segments such as the production of basic petrochemical products (like ethylene and polyethylene), which demand is a function of macroeconomic growth. Many of those competitors based in the Far East and the Middle East are able to benefit from cost economies due to larger plant scale, wide geographic moat, availability of cheap feedstock and proximity to end-markets. Excess capacity across Europe has also fueled competition in this business. Furthermore, petrochemical producers based in the United States have regained market share, as their cost structure has become competitive due to the availability of cheap feedstock deriving from the production of domestic shale gas from which ethane is derived which is a cheaper raw material for the production of ethylene than the oil-based feedstock utilized by Eni's petrochemicals subsidiaries. In 2018 the operating profit of our Chemicals business fell sharply due to increased expenses for oil-based feedstock, which the Company was not able to pass to final products prices pressured by competition. The Company does not expect any meaningful improvement in the trading environment in the short to the medium-term due to competitive headwinds described above.

Management intends to execute an action plan designated to diversify the product portfolio away from the more commoditized products which are exposed to crude oil prices fluctuations and cyclical market dynamics and to focus on higher-value added products, particularly in the green chemicals business and in specialty niche markets, which we believe are less exposed to the economic cycle and to the volatility of crude oil prices. If the Company fails to reduce its exposure to commodity plastics and to gain critical mass in the green chemicals business and in the specialty markets, its future results of operations and cash flows may remain cyclical and exposed to any demand or cost downturn.

Safety, security, environmental and other operational risks

The Group engages in the exploration and production of oil and natural gas, processing, transportation and refining of crude oil, transport of natural gas, storage and distribution of petroleum products and the production of base chemicals, plastics and elastomers. By their nature, the Group's operations expose Eni to a wide range of significant health, safety, security and environmental risks. Technical faults, malfunction of plants, equipment and facilities, control systems failure, human errors, acts of sabotage, loss of containment and adverse weather events can trigger damaging events such as explosions, fires, oil and gas spills from wells, pipeline and tankers, release of contaminants, toxic emissions and other negative events.

The magnitude of these risks is influenced by the geographic range, operational diversity and technical complexity of Eni's activities. Eni's future results of operations and liquidity depend on its ability to identify and mitigate the risks and hazards inherent to operating in those industries.

In the Exploration & Production segment, Eni faces natural hazards and other operational risks including those relating to the physical characteristics of oil and natural gas fields. These include the risks of eruptions of crude oil or of natural gas, discovery of hydrocarbon pockets with abnormal pressure, crumbling of well openings, leaks that can harm the environment and the security of Eni's personnel and risks of blowout, fire or explosion. Accidents at a single well can lead to loss of life, damage or destruction to properties, environmental damage, GHG emissions and consequently potential economic losses that could have a material and adverse effect on the business, results of operations, liquidity, reputation and prospects of the Group, including its share price and dividends.

Eni's activities in the Refining & Marketing and Chemical segment entail health, safety and environmental risks related to the handling, transformation and distribution of oil, oil products and certain petrochemical products. These risks can arise from the intrinsic characteristics and the overall life cycle of the products manufactured and the raw materials used in the manufacturing process, such as oil-based feedstock, catalysts, additives and monomer feedstock. These risks comprise flammability, toxicity, long-term environmental impact such as greenhouse gas emissions and risks of various forms of pollution and contamination of the soil and the groundwater, emissions and discharges resulting from their use and from recycling or disposing of materials and wastes at the end of their useful life.

All of Eni's segments of operations involve, to varying degrees, the transportation of hydrocarbons. Risks in transportation activities depend both on the hazardous nature of the products transported, and on the transportation methods used (mainly pipelines, shipping, river freight, rail, road and gas distribution networks), the volumes involved and the sensitivity of the regions through which the transport passes (quality of infrastructure, population density, environmental considerations). All modes of transportation of hydrocarbons are particularly susceptible to a loss of containment of hydrocarbons and other hazardous materials, and, given the high volumes involved, could present a significant risk to people and the environment.

The Company has invested and will continue to invest significant resources in order to upgrade the methods and systems for safeguarding safety and health of employees, contractors and communities, and the environment; to prevent risks; to comply with applicable laws and policies and to respond to and learn from unforeseen incidents. Eni seeks to minimize these operational risks by carefully designing and building facilities, including wells, industrial complexes, plants and equipment, pipelines, storage sites and other facilities, and managing its operations in a safe and reliable manner and in compliance with all applicable rules and regulations. These measures may not ultimately be completely successful in protecting against those risks. Failure to manage these risks could cause unforeseen incidents, including releases or oil spills, blowouts, fire, mechanical failures and other incidents resulting in personal injury, loss of life, environmental damage, legal liabilities and/or damage claims, destruction of crude oil or natural gas wells, as well as damage to equipment and other property, all of which could lead to a disruption in operations and to negatively affect results and cash flow and the Company's business prospects.

Eni's operations are often conducted in difficult and/or environmentally sensitive locations such as the Gulf of Mexico, the Caspian Sea and the Arctic. In such locations, the consequences of any incident could be greater than in other locations. Eni also faces risks once production is discontinued, because Eni's activities require the decommissioning of productive infrastructures and environmental sites remediation and clean-up. Furthermore, in certain situations where Eni is not the operator, the Company may have limited influence and control over third parties, which may limit its ability to manage and control such risks.

Eni retains worldwide third-party liability insurance coverage, which is designed to hedge part of the liabilities associated with damage to third parties, loss of value to the Group's assets related to unfavorable events and in connection with environmental clean-up and remediation. Maximum compensation is \$1.2 billion in case of offshore incident and \$1.4 billion in case of incident at onshore facilities (refineries). Additionally, the Company may also activate further insurance coverage in case of specific capital projects and other industrial initiatives. Management believes that its insurance coverage is in line with industry practice and is sufficient to cover normal risks in its operations. However, the Company is not insured against all potential risks. In the event of a major environmental disaster, such as the incident which occurred at the Macondo well in the Gulf of Mexico several years ago, for example, Eni's third-party liability insurance would not provide any material coverage and thus the Company's liability would far exceed the maximum coverage provided by its insurance. The loss Eni could suffer in the event of such a disaster would depend on all the facts and circumstances of the event and would be subject to a whole range of uncertainties, including legal uncertainty as to the scope of liability for consequential damages, which may include economic damage not directly connected to the disaster.

The Company cannot guarantee that it will not suffer any uninsured loss and there can be no guarantee, particularly in the case of a major environmental disaster or industrial accident, that such a loss would not have a material adverse effect on the Company.

The occurrence of the above mentioned events could have a material adverse impact on the Group's business, competitive position, cash flow, results of operations, liquidity, future growth prospects and shareholders' returns and damage the Group's reputation.

Risks associated with the exploration and production of oil and natural gas

The exploration and production of oil and natural gas require high levels of capital expenditures and are subject to natural hazards and other uncertainties, including those relating to the physical characteristics of oil and gas fields. The exploration and production activities are subject to the mining risk and the risks of cost overruns and delayed start-up at the projects to develop and produce hydrocarbons reserves. Those risks could have an adverse, significant impact on Eni's future growth prospects, results of operations, cash flows, liquidity and shareholders' returns.

The production of oil and natural gas is highly regulated and is subject to conditions imposed by governments throughout the world in matters such as the award of exploration and production leases, the imposition of specific drilling and other work obligations, income taxes and taxes on production, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. A description of the main risks facing the Company's business in the exploration and production of oil and gas is provided below.

Eni's oil and natural gas offshore operations are particularly exposed to health, safety, security and environmental risks

Eni has material offshore operations relating to the exploration and production of hydrocarbons. In 2018, approximately 56% of Eni's total oil and gas production for the year derived from offshore fields, mainly in, Libya, Norway, Angola, Egypt, the Gulf of Mexico, Italy, Congo, Indonesia, Venezuela, the

United Arab Emirates, the United Kingdom and Nigeria. Offshore operations in the oil and gas industry are inherently riskier than onshore activities. Offshore accidents and spills could cause damage of catastrophic proportions to the ecosystem and health and security of people due to objective difficulties in handling hydrocarbons containment, pollution, poisoning of water and organisms, length and complexity of cleaning operations and other factors. Furthermore, offshore operations are subject to marine risks, including storms and other adverse weather conditions and vessel collisions, as well as interruptions or termination by governmental authorities based on safety, environmental and other considerations. Failure to manage these risks could result in injury or loss of life, damage to property or environmental damage, and could result in regulatory action, legal liability, loss of revenues and damage to Eni's reputation and could have a material adverse effect on Eni's future growth prospects, results of operations, cash flows, liquidity, reputation and shareholders' returns.

Exploratory drilling efforts may be unsuccessful

Exploration drilling for oil and gas involves numerous risks including the risk of dry holes or failure to find commercial quantities of hydrocarbons. The costs of drilling and completing wells have margins of uncertainty, and drilling operations may be unsuccessful because of a large variety of factors, including geological failure, unexpected drilling conditions, pressure or heterogeneities in formations, equipment failures, well control (blowouts) and other forms of accidents. A large part of the Company exploratory drilling operations is located offshore, including in deep and ultra-deep waters, in remote areas and in environmentally sensitive locations (such as the Barents Sea, the Gulf of Mexico and the Caspian Sea). In these locations, the Company generally experiences higher operational risks and more challenging conditions and incurs higher exploration costs than onshore. Furthermore, deep and ultra-deep water operations require significant time before commercial production of discovered reserves can commence, increasing both the financial risks associated with these activities. Because Eni plans to make significant investments in executing exploration projects, it is likely that the Company will incur significant amounts of dry hole expenses in future years. Unsuccessful exploration activities and failure to discover additional commercial reserves could reduce future production of oil and natural gas, which is highly dependent on the rate of success of exploration projects, and could have an adverse impact on Eni's future growth prospects, results of operations, cash flows and liquidity.

Development projects bear significant operational risks which may adversely affect actual returns

Eni is executing or is planning to execute several development projects to produce and market hydrocarbon reserves. Certain projects target the development of reserves in high-risk areas, particularly deep offshore and in remote and hostile environments or in environmentally-sensitive locations. Eni's future results of operations and business prospects depend heavily on its ability to implement, develop and operate major projects as planned. Key factors that may affect the economics of these projects include:

- the outcome of negotiations with joint venture partners, governments and state-owned companies, suppliers, customers or others to define project terms and conditions, including, for example, Eni's ability to negotiate favorable long-term contracts to market gas reserves;
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;
- timely issuance of permits and licenses by government agencies;
- the ability to make the front-end engineering design in order to prevent the occurrence of technical inconvenience during the execution phase; timely manufacturing and delivery of critical equipment by contractors, shortages in the availability of such equipment or lack of shipping yards where complex offshore units such as FPSO and platforms are built; these events may cause cost overruns and delays impacting the time-to-market of the reserves;
- risks associated with the use of new technologies and the inability to develop advanced technologies to maximize the recoverability rate of hydrocarbons or gain access to previously inaccessible reservoirs;
- performance in project execution on the part of contractors who are awarded project construction activities generally based on the EPC (Engineering, Procurement and Construction) contractual scheme;
- changes in operating conditions and cost overruns;

- the actual performance of the reservoir and natural field decline; and
- the ability and time necessary to build suitable transport infrastructures to export production to final markets.

As previously described, events such as poor project execution, inadequate front-end engineering design, delays in the achievement of critical phases and project milestones, delays in the delivery of production facilities and other equipment by third parties, differences between scheduled and actual timing of the first oil, as well as cost overruns may adversely affect the economic returns of Eni's development projects. Failure to deliver major projects on time and on budget could negatively affect results of operations, cash flow and the achievement of short-term targets of production growth. Lastly, the development and marketing of hydrocarbon reserves typically require several years after a discovery is made. This is because a development project involves an array of complex and lengthy activities, including appraising a discovery in order to evaluate the technical and economic feasibility of the development project, project final investment decision and building and commissioning the related plants and facilities. As a consequence, rates of return for such long lead time projects are exposed to the volatility of oil and gas prices and costs which may be substantially different from those estimated when the investment decision was made, thereby leading to lower return rates. Moreover, projects executed with partners and joint venture partners reduce the ability of the Company to manage risks and costs, and Eni could have limited influence over and control of the operations and performance of its partners. Furthermore, Eni may not have full operational control of the joint ventures in which it participates and may have exposure to counterparty credit risk and disruption of operations and strategic objectives due to the nature of its relationships.

Finally, if the Company is unable to develop and operate major projects as planned, particularly if the Company fails to accomplish budgeted costs and time schedules, it could incur significant impairment losses of capitalised costs associated with reduced future cash flows of those projects.

Inability to replace oil and natural gas reserves could adversely impact results of operations and financial condition

Unless the Company is able to replace produced oil and natural gas, its reserves will decline. In addition to being a function of production, revisions and new discoveries, the Company's reserve replacement is also affected by the entitlement mechanism in its production sharing agreements ("PSAs"), whereby the Company is entitled to a portion of a field's reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The higher the reference prices for Brent crude oil used to estimate Eni's proved reserves, the lower the number of barrels necessary to recover the same amount of expenditure, and vice versa. Based on the current portfolio of oil and gas assets, Eni's management estimates that production entitlements vary on average by approximately 600 BBL/d for each $1 change in oil prices based on current Eni's assumptions for oil prices. This led to negative reserves revisions of 38 mmBOE in 2018, due to the oil price increase previously described. In case oil prices differ significantly from Eni's own forecasts, the result of the above mentioned sensitivity of production to oil price changes may be significantly different.

Future oil and gas production is dependent on the Company's ability to access new reserves through new discoveries, application of improved techniques, success in development activity, negotiations with national oil companies and other entities owners of known reserves and acquisitions.

An inability to replace produced reserves by discovering, acquiring and developing additional reserves could adversely impact future production levels and growth prospects. If Eni is unsuccessful in meeting its long-term targets of production growth and reserve replacement, Eni's future total proved reserves and production will decline and this will negatively affect future results of operations, cash flow and business prospects.

Uncertainties in estimates of oil and natural gas reserves

The accuracy of proved reserve estimates and of projections of future rates of production and timing of development expenditures depends on a number of factors, assumptions and variables, including:

- the quality of available geological, technical and economic data and their interpretation and judgement;
- projections regarding future rates of production and costs and timing of development expenditures;
- changes in the prevailing tax rules, other government regulations and contractual conditions;

- results of drilling, testing and the actual production performance of Eni's reservoirs after the date of the estimates which may drive substantial upward or downward revisions; and
- changes in oil and natural gas prices which could affect the quantities of Eni's proved reserves since the estimates of reserves are based on prices and costs existing as of the date when these estimates are made. Lower oil prices or the projections of higher operating and development costs may impair the ability of the Company to economically produce reserves leading to downward reserve revisions.

Reserve estimates are subject to revisions as prices fluctuate due to the cost recovery mechanism under the Company's production sharing agreements and similar contractual schemes.

Many of the factors, assumptions and variables involved in estimating proved reserves are subject to change over time and therefore affect the estimates of oil and natural gas reserves.

The prices used in calculating Eni's estimated proved reserves are, in accordance with the U.S. Securities and Exchange Commission (the "U.S. SEC") requirements, calculated by determining the unweighted arithmetic average of the first-day-of-the-month commodity prices for the preceding 12 months. For the 12-months ending December 31, 2018, average prices were based on 71.4 $/BBL for the Brent crude oil.

Brent prices have declined significantly since they reached a peak at 85 $/BBL in October of 2018 and in the first quarter of 2019 have recovered only partially. If such prices do not increase significantly in the coming months, our future calculations of estimated proved reserves will be based on lower commodity prices which could result in our having to remove non-economic reserves from our proved reserves in future periods. This effect could be counterbalanced in full or in part by increased reserves corresponding to the additional volume entitlements under Eni's PSAs relating to cost oil: i.e. because of lower oil and gas prices, the reimbursement of expenditures incurred by the Company requires additional volumes of reserves.

Accordingly, the estimated reserves reported as of the end of 2018 could be significantly different from the quantities of oil and natural gas that will be ultimately recovered. Any downward revision in Eni's estimated quantities of proved reserves would indicate lower future production volumes, which could adversely impact Eni's business prospects, results of operations, cash flows and liquidity.

The development of the Group's proved undeveloped reserves may take longer and may require higher levels of capital expenditures than it currently anticipates or the Group's proved undeveloped reserves may not ultimately be developed or produced.

At December 31, 2018, approximately 32% of the Group's total estimated proved reserves (by volume) were undeveloped and may not be ultimately developed or produced. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The Group's reserve estimates assume it can and will make these expenditures and conduct these operations successfully. These assumptions may not prove to be accurate. The Group's reserve report at December 31, 2018 includes estimates of total future development and decomissioning costs associated with the Group's proved total reserves of approximately €35.3 billion (undiscounted, including consolidated subsidiaries and equity-accounted entities). It cannot be certain that estimated costs of the development of these reserves will prove correct, development will occur as scheduled, or the results of such development will be as estimated. In case of change in the Company's plans to develop those reserves, or if it is not otherwise able to successfully develop these reserves as a result of the Group's inability to fund necessary capital expenditures or otherwise, it will be required to remove the associated volumes from the Group's reported proved reserves.

Oil and gas activity may be subject to increasingly high levels of income taxes and royalties

Oil and gas operations are subject to the payment of royalties and income taxes, which tend to be higher than those payable in many other commercial activities. Furthermore, in recent years, Eni has experienced adverse changes in the tax regimes applicable to oil and gas operations in a number of countries where the Company conducts its upstream operations. As a result of these trends, management estimates that the tax rate applicable to the Company's oil and gas operations is materially higher than the Italian statutory tax rate for corporate profit, which currently stands at 24%.

Management believes that the marginal tax rate in the oil and gas industry tends to increase in correlation with higher oil prices, which could make it more difficult for Eni to translate higher oil prices into increased net profit. However, the Company does not expect that the marginal tax rate will decrease in response to falling oil prices. Adverse changes in the tax rate applicable to the Group's profit before income taxes in its oil and gas operations would have a negative impact on Eni's future results of operations and cash flows.

In the current uncertain financial and economic environment, governments are facing greater pressure on public finances, which may induce them to intervene in the fiscal framework for the oil and gas industry, including the risk of increased taxation, windfall taxes, and even nationalizations and expropriations.

Eni's results and cash flow depend on its ability to identify and mitigate the above mentioned risks and hazards which are inherent to its operations.

The present value of future net revenues from Eni's proved reserves will not necessarily be the same as the current market value of Eni's estimated crude oil and natural gas reserves

The present value of future net revenues from Eni's proved reserves may differ from the current market value of Eni's estimated crude oil and natural gas reserves. In accordance with U.S. SEC rules, Eni bases the estimated discounted future net revenues from proved reserves on the 12-month un-weighted arithmetic average of the first-day-of-the-month commodity prices for the preceding twelve months. Actual future prices may be materially higher or lower than the U.S. SEC pricing used in the calculations. Actual future net revenues from crude oil and natural gas properties will be affected by factors such as:

- the actual prices Eni receives for sales of crude oil and natural gas;
- the actual cost and timing of development and production expenditures;
- the timing and amount of actual production; and
- changes in governmental regulations or taxation.

The timing of both Eni's production and its incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. Additionally, the 10% discount factor Eni uses when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with Eni's reserves or the crude oil and natural gas industry in general. At December 31, 2018, the net present value of Eni's proved reserves totaled approximately €57.6 billion. The average prices used to estimate Eni's proved reserves and the net present value at December 31, 2018, as calculated in accordance with U.S. SEC rules, were 71.4 $/BBL for the Brent crude oil. Actual future prices may materially differ from those used in our year-end estimates. Commodity prices have decreased significantly in recent months. Holding all other factors constant, if commodity prices used in Eni's year-end reserve estimates were in line with the pricing environment existing in the first quarter of 2019, Eni's PV-10 at December 31, 2019 could decrease significantly.

Oil and gas activity may be subject to increasingly high levels of regulations throughout the world, which may impact our extraction activities and the recoverability of reserves

The production of oil and natural gas is highly regulated and is subject to conditions imposed by governments throughout the world in matters such as the award of exploration and production leases, the imposition of specific drilling and other work obligations, environmental protection measures, control over the development and abandonment of fields and installations, and restrictions on production. These risks can limit the Group access to hydrocarbons reserves or may have the Group to redesign, curtail or cease its oil&gas operation with significant effects on the Group business prospects, results of operations and cash flow.

In Italy, a new law has been enacted effective February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan intended to identify areas that are suitable for carrying out exploration, development and production of hydrocarbons in the national territory, including the territorial seawaters. Until approval of such a plan, it is established a moratorium on exploration activities, including the award of new exploration leases. Following the plan approval, exploration permits resume their efficacy in areas that have been identified as suitable; on the contrary, in unsuitable areas, exploration permits are repealed.

As far as development and production concessions are concerned, pending the national plan approval, ongoing concessions retain their efficacy and administrative procedures underway to grant extension to expired concession remain unaffected; instead no applications to obtain new concession can be filed. Once the above mentioned national plan is adopted, development and production concessions that fall in suitable areas can be granted further extensions and applications for new concessions can be filed; on the contrary development and production concessions current at the approval of the national plan that fall in unsuitable areas are repealed at their expiration and no further extensions can be granted, nor new concession applications can be filed.

In case Italian administrative bodies fail to adopt the national plan for suitable areas within two years from the law enactment, the general moratorium on exploration activities is revoked and application for new concession permits can be filed. According to the statute, areas that are suitable to the activities of exploring and developing hydrocarbons must conform to a number of criteria including morphological characteristics and social, urbanistic and industrial constraints, with particular bias for the hydrogeological balance, current territorial planning and with regard to marine areas for externalities on the ecosystem, reviews of marine routes, fishing and any possible impacts on the coastline.

Our largest development project in Italy is operated under a concession that will expire in 2019; the application for renewal is underway and the renewal process is unaffected by the new law; assuming it is renewed as expected, this concession will expire in 2029, unless renewed at that time. Production at those sites is currently scheduled to continue until 2045.

Management believes the criteria laid out in the law for identified unsuitable areas to be high-level principles, which make it difficult identifying in a reliable and objective manner areas that might be suitable or unsuitable to hydrocarbons activities before the plan adoption by Italian authorities. Therefore, management is not currently in the position to make a reliable and fair estimation of future impacts of the new law provisions on the recoverability of the volumes of proved reserves booked in Italy and the associated future cash flows. However, based on the review of all facts and circumstances and on the current knowledge of the matter, management does not expects any material impacts on the Group future results of operations and cash flow.

Political considerations

The large majority of Eni's oil and gas reserves are located in countries outside Europe and North America, mainly in Africa, Central Asia and Central-Southern America, where the socio-political framework, the financial system and the macroeconomic outlook are less stable than in the OECD countries. In those non-OECD countries, Eni is exposed to a wide range of additional risks and uncertainties in addition to the material risks described above, which could materially impact the ability of the Company to conduct its oil&gas operations in a safe, reliable and profitable manner.

As of December 31, 2018, approximately 82% of Eni's proved hydrocarbon reserves were located in such countries. Adverse political, social and economic developments, such as internal conflicts, revolutions, establishment of non-democratic regimes, protests, strikes and other forms of civil disorder, contraction of economic activity and financial difficulties of the local governments with repercussions on the solvency of state institutions, inflation levels, exchange rates and similar events in those non-OECD countries may impair Eni's ability to continue operating in an economically viable way, either temporarily or permanently, and Eni's ability to access oil and gas reserves. In particular, Eni faces risks in connection with the following, possible issues:

- lack of well-established and reliable legal systems and uncertainties surrounding the enforcement of contractual rights;
- unfavorable enforcement of laws, regulations and contractual arrangements leading, for example, to expropriation, nationalization or forced divestiture of assets and unilateral cancellation or modification of contractual terms. Eni is facing increasing competition from state-owned oil

companies that are partnering Eni in a number of oil and gas projects and properties in the host countries where Eni conducts its upstream operations. These state-owned oil companies can unilaterally change contractual terms and other conditions of oil and gas projects in order to obtain a larger share of profit from a given project, thereby reducing Eni's profit share. They can also enforce different interpretations of contractual clauses relating to the recovery of certain expenses incurred by the Company to produce hydrocarbons reserves in any given project;

- sovereign default or financial instability due to the fact that those Countries rely heavily on petroleum revenues to sustain public finance and petroleum revenues have dramatically contracted during the recent, three-year long oil downturn which ended by mid of 2017. Financial difficulties at country level often translate into failure on part of state-owned companies and agencies to fulfill their financial obligations towards Eni relating to funding capital commitments in projects operated by Eni or to timely paying supplies of equity oil and gas volumes;
- restrictions on exploration, production, imports and exports;
- tax or royalty increases (including retroactive claims);
- political and social instability which could result in civil and social unrest, internal conflicts and other forms of protest and disorder such as strikes, riots, sabotage, acts of violence and similar events. These risks could result in disruptions to economic activity, loss of output, plant closures and shutdowns, project delays, the loss of assets and threat to the security of personnel. They may disrupt financial and commercial markets, including the supply of and pricing for oil and natural gas, and generate greater political and economic instability in some of the geographical areas in which Eni operates;
- difficulties in finding qualified suppliers in critical operating environments; and
- complex processes of granting authorizations or licences affecting time-to-market of certain development projects.

Areas where Eni operates and where the Company is particularly exposed to political risk include, but are not limited to: Libya, Egypt, Algeria, Nigeria, Angola, Kazakhstan, Venezuela and Iraq. Additionally, any possible reprisals because of military or other action, such as acts of terrorism in Europe, the United States or elsewhere, could have a material adverse effect on Eni's business, results of operations and financial condition.

In recent years, Eni's operations in Libya were materially affected by the revolution of 2011 and a change of regime, which caused a prolonged period of political and social instability, still ongoing. In 2011 Eni's operations in the country experienced an almost one-year long shutdown due to security issues amidst a civil war, causing a material impact on the Group results of operation and cash flow of the year. In subsequent years Eni has experienced frequent disruptions at its operations albeit of a smaller scale than in 2011 due to security threats to its installations and personnel. In the second half of 2018 a resurgence of socio-political instability coupled with internal clashes reduced the Country economic activity and gas demand which negatively affected the Company's levels of production for the year. Management is closely monitoring the situation and is evaluating any possible measure to safeguard safety of Eni's local personnel and security of plants and production infrastructures. Going forward, management believes that Libya's geopolitical situation will continue to represent a source of risk and uncertainty to Eni's operations in the Country. Currently, Libya represents approximately 16% of the Group's total production; this proportion is forecasted to decrease in the medium term. In the event of major adverse events such as the resumption of internal conflict, acts of war, sabotage, social unrest, clashes and other forms of civil disorder, Eni could be forced to interrupt or reduce its producing activities at the Libyan plants, negatively affecting Eni's results of operations, cash flow and business prospects.

Venezuela is currently experiencing a situation of financial stress amidst an economic downturn due to lack of resources to support the development of the country's hydrocarbons reserves, which have negatively affected the Country production levels and hence petroleum revenues. The situation has been made worse by certain international sanctions targeting the country's financial system and its ability to export crude oil to the USA market, which is the main outlet of Venezuelan production, which are described below. Eni expects the financial and political outlook of Venezuela to negatively affect its ability to recover the investments made in the Country to develop two petroleum projects and the overdue trade receivables owned to us by the Venezuelan national oil company – PDVSA – and its affiliates for the gas supplies of the Cardon IV gas project, a 50 per cent. – held joint venture. In 2018, this venture was able to collect a certain percentage of the sales of the equity gas produced in the year to PDVSA. The venture is systematically accounting a loss provision on the uncollected revenues based on management's appreciation of the counterparty risk which was estimated based on the findings of a review of the past experience of sovereign defaults. Furthermore, due to a worsening operating environment, management decided to de-book the proved undeveloped reserves (down 106 million BBL) at one of the Company's projects in the Country, recognizing an impairment loss of around €200 million.

Nigeria is also undergoing a situation of financial stress, which has translated into continuing delays in collecting overdue trade receivables and credits for the carry of the expenditures of the Nigerian joint operators at projects operated by Eni and the incurrence of credit losses. Further, Eni's activities in Nigeria have been impacted in recent years by continuing incidences of theft, acts of sabotage and other similar disruptions, which have jeopardized the Company's ability to conduct operations in full security, particularly in the onshore area of the Niger Delta. Eni expects that those risks will continue to affect Eni's operations in Nigeria and other countries.

It is possible that the Group may incur further asset impairments or credit losses in future reporting periods depending on the evolution of the financial outlook of the Countries where the Group is conducting its oil&gas operations.

In Egypt, Eni plans to invest significantly in the next four-year plan to sustain the production plateau at the Zohr offshore gas field and to develop existing gas reserves at other projects. Since our gas production is entirely sold to local state-owned oil companies, we expect a significant increase in the credit risk exposure in Egypt, where we experienced some issues at collecting overdue trade receivables during the downturn. Eni will continue monitoring the counterparty risk in future years considering the significant volumes of gas expected to be supplied to Egypt's national oil companies.

Eni closely monitors political, social and economic risks of the countries in which it has invested or intends to invest, in order to evaluate the economic and financial return of certain projects and to selectively evaluate projects. While the occurrence of those events is unpredictable, the occurrence of any such events could adversely affect Eni's results from operations, cash flow and business prospects, also including the counterparty risk arising from the financing exposure of Eni in case state-owned entities, which are party to Eni's upstream projects for developing hydrocarbons, fail to reimburse due amounts.

Sanction targets

In response to the Russia-Ukraine crisis, the European Union and the United States have enacted sanctions targeting, inter alia, the financial and energy sectors in Russia by restricting the supply of certain oil and gas items and services to Russia and certain forms of financing. Eni has adapted its activities to the applicable sanctions and will adapt its business to any further restrictive measures that could be adopted by the relevant authorities. Recently, the US government has tightened the sanction regime against Russia by enacting the "Countering America's Adversaries Through Sanctions Act". In response to these new measures, the Company could possibly refrain from pursuing business opportunities in Russia, while currently the Company is not engaged in any upstream projects in Russia.

It is possible that wider sanctions targeting the Russian energy, banking and/or finance industries may be implemented. Further sanctions imposed on Russia, Russian citizens or Russian companies by the international community, such as restrictions on purchases of Russian gas by European companies or measures restricting dealings with Russian counterparties, could adversely impact Eni's business, results of operations and cash flow. Furthermore, an escalation of the international crisis, resulting in a tightening of sanctions, could entail a significant disruption of energy supply and trade flows globally, which could have a material adverse effect on the Group's business, financial conditions, results of operations and prospects.

In 2017, the US Administration enacted certain financing sanctions against Venezuela, which prohibit any US person to be involved in all transactions related to, provision of financing for, and other dealings in, among other things, any debt owed to the Government of Venezuela that is pledged as collateral after the effective date, including accounts receivable. Recently the US administration has resolved to impose an embargo on the import of crude oil from Venezuela state-owned oil company, PDVSA and has restricted the ability of US dealers to trade bonds issued by the Government of Venezuela and its affiliates. These sanctions do not affect directly Eni's activities, which however are affected by the worsening financial, political and operating outlook of the country which could limit the ability of Eni to recover its investments.

Risks in the Company's Gas & Power business

Risks associated with the trading environment and competition in the gas market

Until 2018, our Gas & Power segment has recorded a history of weak profitability and losses due to the changed fundamentals of the wholesale gas markets in Europe following the gas downturn of 2013 – 2014. Competition escalated driven by muted demand growth, oversupplies and the increasing weigh in the European energy mix of governmental-subsided renewable energy sources (particularly the photovoltaic). The large-scale development of shale gas in the United States was another factor contributing to the oversupply situation in Europe, because many LNG projects worldwide that originally targeted the US market were redirected to an already saturated European market. Furthermore, a number of re-gasification terminals in the US have been upgraded to gas liquefaction facilities with the aim of exporting the US gas surplus. Large gas supplies to Europe led to the development of liquid spot markets where gas is traded daily. Prices at those hubs became the main indexation parameter of selling prices, replacing prices contractually agreed in bilateral negotiations between gas buyers and gas wholesalers. Increased competition, market liquidity and indexation mismatch between gas purchase prices and selling prices determined a squeeze of margins on gas sales. These trends were exacerbated by the contractual commitments taken by the Company to supply gas to end-markets in Europe. A few years ago, before the onset of the European gas downturn, the Company signed with the main countries supplying gas to Europe (Russia, Algeria, the Netherlands, Libya and Norway) long-term gas supply contracts with take-or-pay clauses, which would expose us to a volume risk, as the Company was contractually required to purchase minimum annual amounts of gas or, in case of failure, to pay the corresponding price. Additionally, Eni booked the transportation rights along the main gas backbones across Europe to deliver its contracted gas volumes to end-markets. In a weak market, the need to dispose of the minimum off-take of gas negatively affected Eni's margins. Those market trends have negatively affected the operating performance of our Gas & Power segment from the beginning of the market crisis throughout 2017, when this segment closed at breakeven. However, in 2018 the segment posted a significant recovery in profitability due to the benefits of the renegotiations of its long-term gas supply contracts and other drivers. Furthermore, in 2018 gas demand and supplies in Europe were more balanced due to a certain recovery in demand supported by the phase out of a number of coal-fired power plants and lower production from nuclear plants, a slowdown in the final investment decisions in new liquefaction capacity due to the oil downturn and increasing gas demand from China. Looking forward, the Company expects that a muted demand environment in Europe driven by an ongoing economic slowdown will increase the risks of oversupplies and margin pressure.

Against the backdrop of a challenging competitive environment, Eni anticipates a number of risk factors to the profitability outlook of the Company's gas marketing business over the four-year planning period, considering the Company's operational constraints dictated by its long-term supply contracts with take-or-pay clauses and its structure of fixed costs linked to the transportation rights at the main European backbones booked for multi-year periods. Such risk factors include continuing oversupplies, pricing pressures, volatile margins and the risk of deteriorating spreads of Italian spot prices versus continental benchmarks. The results of Eni's wholesale business are particularly exposed to the volatility of the spreads between spot prices at European hubs and Italian spot prices because the Group's supply costs are mainly linked to prices at European hubs, whereas a large part of the Group's selling volumes are linked to Italian spot prices which, historically, have been higher due to the costs of logistics and other factors. This price differential enables the Company to recover its fixed operating expenses in the gas wholesale business. Risks are raising that spot prices in Italy could converge with prices at continental hubs due to the current slowdown of gas demand in Europe and in Italy and the return of LNG spot volumes at European markets and also at Italian regasification terminals. Longer-term there are risks of an oversupply build in the Italian market due to the expected entry into operations of a project to import gas from the Caspian region to Italy and other developments. A reduction of the spread between Italian spot prices and European spot prices for gas could negatively affect the profitability of our business by reducing the total addressable market and the related opportunities to monetize the flexibilities of our gas portfolio, as in the case of the possibility to lift additional gas volumes in addition to the annual minimum quantity at our take-or-pay contracts up the annual contractual quantity in case of favorable market conditions.

Eni's management is planning to continue its strategy of renegotiating the Company's long-term gas supply contracts in order to constantly align pricing and volume terms to current market conditions as they evolve, considering the risk factors described above. The revision clauses provided by these contracts state the right of each counterparty to renegotiate the economic terms and other contractual conditions periodically, in relation to ongoing changes in the gas scenario. Management believes that the outcome of those renegotiations is uncertain in respect of both the amount of the economic benefits that will be ultimately obtained and the timing of recognition of profit. Furthermore, in case Eni and the gas suppliers fail to agree on revised contractual terms, the claiming party has the ability to open an arbitration procedure to obtain revised contractual conditions. However, the suppliers might also file counterclaims with the arbitration panel seeking to dismiss Eni's request for a price review and may also claim an increase in the price of the gas supplied to Eni based on their own view of markets dynamics. All these possible developments within the renegotiation process could increase the level of risks and uncertainties relating the outcome of those renegotiations.

Current, negative trends in gas demands and supplies may impair the Company's ability to fulfil its minimum off-take obligations in connection with its take-or-pay, long-term gas supply contracts

In the years preceding the European gas downturn of 2013 – 2014, Eni signed a number of long-term gas supply contracts with national operators of certain key producing countries, from where most of the European gas supplies are sourced (Russia, Algeria, Libya, the Netherlands and Norway). These contracts were intended to secure Eni long-term access to gas supplies, particularly with a view to supplying the Italian gas market and in anticipation of certain pargets of gas demand growth, which however would fall short of industry's projections.

These contracts include take-or-pay clauses whereby the Company has an obligation to lift minimum, pre-set volumes of gas in each year of the contractual term or, in case of failure, to pay the whole price, or a fraction of that price, up to the minimum contractual quantity. Similar considerations apply to ship-or-pay contractual obligations. Long-term gas supply contracts with take-or-pay clauses expose the Company to a volume risk, as the Company is obligated to purchase an annual minimum volume of gas, or in case of failure, to pay the underlying price.

Management believes that the current level of market liquidity, the outlook of the European gas sector which is featuring muted demand growth, strong competitive pressures and large supplies, as well as any possible change in sector-specific regulation represent risk factors to the Company's ongoing ability to fulfil its minimum take obligations associated with its long-term supply contracts.

Risks associated with sector-specific regulations in Italy

Risks associated with the regulatory powers entrusted to the Italian Regulatory Authority for Energy, Networks and Environment in the matter of pricing to residential customers

Eni's Gas & Power segment is subject to regulatory risks mainly in its domestic market in Italy. The Italian Regulatory Authority for Energy, Networks and Environment (the "Authority") is entrusted with certain powers in the matter of natural gas pricing. Specifically, the Authority retains a surveillance power on pricing in the natural gas market in Italy and the power to establish selling tariffs for the supply of natural gas to residential and commercial users until the market is fully opened.

Developments in the regulatory framework intended to increase the level of market liquidity or of de-regulation, or intended to reduce operators' ability to transfer to customers cost increases in raw materials may negatively affect future sales margins of gas and electricity, operating results and cash flow.

Environmental, health and safety regulations

Eni has incurred in the past, and will continue incurring, material operating expenses and expenditures, and is exposed to business risk in relation to compliance with applicable environmental, health and safety regulations in future years, including compliance with any national or international regulation on GHG emissions

Eni is subject to numerous EU, international, national, regional and local laws and regulations regarding the impact of its operations on the environment and health and safety of employees, contractors, communities and properties. Generally, these laws and regulations require acquisition of a permit before drilling for hydrocarbons may commence, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with exploration, drilling and production activities, including refinery and petrochemical plant operations, limit or prohibit drilling activities in certain protected areas, require to remove and dismantle drilling platforms and other equipment and well plug-in once oil and gas operations have terminated, provide for measures to be taken to protect the safety of the workplace and health of communities involved by the Company's activities, and impose criminal or civil liabilities for polluting the environment or harming employees' or communities' health and safety resulting from the Group's operations.

These laws and regulations set limits to the emission of scrap substances and pollutants and discipline the handling of hazardous materials and discharges of water contaminants nad nocive air emissions resulting from the operation of oil and natural gas extraction and processing plants, petrochemical plants, refineries, service stations, vessels, oil carriers, pipeline systems and other facilities owned or operated by Eni. In addition, Eni's operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste.

Breaches of environmental, health and safety laws and regulations as in the case of negligent or willful release of pollutants into the atmosphere, the soil or groundwater or the overcome of concentration threshold of contaminants set by the law expose the Company to the incurrence of liabilities associated with compensation for environmental, health or safety damage and expenses for environmental remediation and clean-up. Furthermore, in the case of violation of certain rules regarding the safeguard of the environment and safety in the workplace and of communities, the Company may be liable for the negligent or willful conduct on part of its employees as per Italian Law Decree No. 231/2001, which assumes that any misconduct of employees in the field of environmental and health matters can be ascribed to the Company.

Environmental, health and safety laws and regulations have a substantial impact on Eni's operations. Management expects that the Group will continue to incur significant amounts of operating expenses and expenditures in the foreseeable future to comply with laws and regulations and to safeguard the environment, safety in the workplace, health of employees, contractors and communities involved by the Company operations, including:

- costs to prevent, control, eliminate or reduce certain types of air and water emissions and handle waste and other hazardous materials, including the costs incurred in connection with government action to address climate change;
- remedial and clean-up measures related to environmental contamination or accidents at various sites, including those owned by third parties (see discussion below);
- damage compensation claimed by individuals and entities, including local, regional or state administrations, should Eni cause any kind of accident, oil spill, well blowouts, pollution, contamination, emission of GHG above permitted levels or of any other hazardous gases, water, ground or air contaminants or pollutants, as a result of its operations or if the Company is found guilty of violating environmental laws and regulations; and
- costs in connection with the decommissioning and removal of drilling platforms and other facilities, and well plugging at the end of oil&gas field production.

As a further result of any new laws and regulations or other factors, like the actual or alleged occurrence of environmental damage at Eni's plants and facilities, the Company may be forced to curtail, modify or cease certain operations or implement temporary shutdowns of facilities, which could diminish Eni's productivity and materially and adversely impact Eni's results of operations, cash flow and liquidity.

Risks of environmental, health and safety incidents and liabilities are inherent in many of Eni's operations and products. Management believes that Eni adopts high operational standards to ensure safety in running its operations and safeguard of the environment and the health of employees, contractors and communities. In spite of such measures, it is possible that incidents like blowouts, oil spills, contaminations, pollution, and release in the air, soil and ground water of pollutants and other dangerous materials, liquids or gases, and other similar events could occur that would result in damage, also of large proportion and reach, to the environment, employees, contractors, communities and property. The occurrence of any such events could have a material adverse impact on the Group's business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders' returns and damage to the Group's reputation.

Eni has incurred in the past and may incur in the future material environmental liabilities in connection with the environmental impact of its past and present industrial activities. Eni is also exposed to claims under environmental requirements and, from time to time, such claims have been made against us. Furthermore, environmental requirements and regulations in Italy and elsewhere typically impose strict liability. Strict liability means that in some situations Eni could be exposed to liability for clean-up and remediation costs, environmental damage, and other damages as a result of Eni's conduct of operations that was lawful at the time it occurred or of the conduct of prior operators or other third parties. In addition, plaintiffs may seek to obtain compensation for damage resulting from events of contamination and pollution or in case the Company is found liable of violations of any environmental laws or regulations.

In Italy, Eni is exposed to the risk of expenses and environmental liabilities in connection with the impact of its past activities at certain industrial hubs where the Group's products were produced, processed, stored, distributed or sold, such as chemical plants, mineral-metallurgic plants, refineries and other facilities, which were subsequently disposed of, liquidated, closed or shut down. At these industrial hubs, Eni has undertaken a number of initiatives to remediate and to clean-up proprietary or concession areas that were allegedly contaminated and polluted by the Group's industrial activities. State or local public administrations have sued Eni for environmental and other damages and for clean-up and remediation measures in addition to those which were performed by the Company, or which the Company committed to perform. In some cases, Eni has been sued for alleged breach of criminal laws (for example for alleged environmental crimes such as failure to perform soil or groundwater reclamation, environmental disaster and contamination, discharge of toxic materials, amongst others). Although Eni believes that it may not be held liable for having exceeded in the past pollution thresholds that are unlawful according to current regulations but were allowed by laws then effective, nor because the Group took over operations from third parties, it cannot be excluded that Eni could potentially incur such environmental liabilities.

Eni's financial statements account for provisions relating to the costs to be incurred with respect to clean-ups and remediation of contaminated areas and groundwater for which a legal or constructive obligation exists and the associated costs can be reasonably estimated in a reliable manner, regardless of any previous liability attributable to other parties. The accrued amounts represent management's best estimates of the Company's existing liabilities.

Management believes that it is possible that in the future Eni may incur significant environmental expenses and liabilities in addition to the amounts already accrued due to: (i) the likelihood of as yet unknown contamination; (ii) the results of ongoing surveys or surveys to be carried out on the environmental status of certain Eni's industrial sites as required by the applicable regulations on contaminated sites; (iii) unfavourable developments in ongoing litigation on the environmental status of certain of the Company's sites where a number of public administrations and the Italian Ministry of the Environment act as plaintiffs; (iv) the possibility that new litigation might arise; (v) the probability that new and stricter environmental laws might be implemented; and (vi) the circumstance that the extent and cost of environmental restoration and remediation programs are often inherently difficult to estimate leading to underestimation of the future costs of remediation and restoration, as well as unforeseen adverse developments both in the final remediation costs and with respect to the final liability allocation among the various parties involved at the sites.

As a result of those risks, environmental liabilities could be substantial and could have a material adverse effect on Eni's results of operations, cash flow, financial condition, business prospects, reputation and shareholders' value, including dividends and the share price.

Rising public concern related to climate change has led and could continue to lead to the adoption of national and international laws and regulations which are expected to result in a decrease of demand for hydrocarbons and increased compliance costs for the Company. Eni is also exposed to risks of technological breakthrough in the energy field and risks of unpredictable extreme meteorological events linked to the climate change. All these developments may adversely affect the Group's profitability, businesses outlook and reputation

Growing worldwide public concern over greenhouse gas (GHG) emissions and climate change, as well as increasingly regulations in this area, could adversely affect the Group's business and reputation, increase its operating costs and reduce its results of operations, cash flow, financial condition, business prospects and shareholders returns. Those risks may emerge in the short and medium-term, as well as over the long-term.

The scientific community has established a link between climate change and increasing GHG concentration in the atmosphere. International efforts to limit global warming have led, and Eni expects them to continue to lead, to new laws and regulations designed to reduce GHG emissions that are expected to bring about a gradual reduction in the use of fossil fuel over the medium to long-term, notably through the diversification of the energy mix.

Governmental institutions have responded to the issue of climate change on two fronts: on one side, governments can both impose taxes on GHG emissions and incentivize a progressive shift in the energy mix away from fossil fuels, for example, by subsidizing the power generation from renewable sources.

Some governments have already introduced carbon pricing schemes, which can be an effective measure to reduce GHG emissions at the lowest overall cost to society. Today, about half of the GHG direct emissions coming from Eni operated assets are already included in national or supranational Carbon Pricing Mechanisms, such as the European Emission Trading Scheme. Eni expects that more governments will adopt similar schemes and that a growing share of the Group's GHG emissions will be subject to carbon-pricing and other forms of climate regulation in the short to medium term. Eni expects that governments require companies to apply technical measures to reduce their GHG emissions. Eni is already incurring operating costs related to its participation in the European Emission Trading Scheme, whereby Eni is required to purchase on the open markets emission allowances in case its GHG emissions exceed freely-assigned emission allowances (see Note 27 to the Financial Statements). In 2018 to comply with this carbon emissions scheme, Eni purchased on the open market allowances corresponding to 12.7 million tonnes of CO_2 emissions. In certain jurisdictions, Eni is also subject to carbon pricing schemes in Norway. Due to the likelihood of new regulations in this area, Eni expects additional compliance obligations with respect to the release, capture, and use of carbon dioxide that could result in increased investments and higher project costs for Eni and could have a material adverse effect on Eni's operating costs and results of operations, cash flow, financial condition, business prospects and shareholders' returns. Eni also expects that governments will also require companies to apply technical measures to reduce their GHG emissions.

Eni expects that the achievement of the Paris Agreement goal of holding the increase in global average temperature to less than 2° C above pre-industrial levels, or the more stringent goal advocated by the Intergovernmental Panel on Climate Change (IPCC) to limit global warming to 1.5°C, will strengthen the global response to the threat of climate change and spur governments to introduce further measures and policies targeting the reduction of GHG emissions, which will reduce local demand for fossil fuels, thus negatively affecting global demand for oil and natural gas. Eni's business depends on the global demand for oil and natural gas. If existing or future laws, regulations, treaties, or international agreements related to GHG and climate change, including incentives to preserve energy or use alternative energy sources, technological breakthrough in the field of renewable energies or mass-adoption of electric vehicles reduce the worldwide demand for oil and natural gas by a large amount, Eni's results of operations, cash flow, financial condition, business prospects and shareholders' returns may be significantly and adversely affected.

The scientific community has concluded that increasing global average temperatures produces significant physical effects, such as the increased frequency and severity of hurricanes, storms, droughts, floods or other extreme climatic events that could interfere with Eni's operations and damage Eni's facilities. Extreme and unpredictable weather phenomena can result in material disruption to Eni's operations, and consequent loss of or damage to properties and facilities, as well as a loss of output, loss of revenues, increasing maintenance and repair expenses and cash flow shortfall.

Finally, there is a reputational risk linked to the fact that oil companies are increasingly perceived by institutions and the general public as the entities responsible of the global warming due to GHG emissions across the value chain and in particular related with the use of energy products. This could possibly make Eni's shares less attractive to investment funds and individual investors who have been more and more assessing the risk profile of companies against their carbon footprint when making investment decisions. This trend could have a material adverse effect on the price of our securities and our ability to access equity or other capital markets. Additionally, the World Bank has announced plans to stop financing upstream oil and gas projects in 2019. Similarly, according to press reports, other financial institutions also appear to be considering limiting their exposure to certain fossil fuel projects. Accordingly, our ability to use financing for future projects may be adversely impacted. This could also adversely impact our potential partners' ability to finance their portion of costs, either through equity or debt.

Further, in some countries, governments and regulators have filed lawsuits seeking to hold fossil fuel companies, including Eni, liable for costs associated with climate change. Losing any of these lawsuits could have a material adverse effect on our results of operations, cash flows, liquidity and business prospects.

Risks related to legal proceedings and compliance with anti-corruption legislation

Eni is the defendant in a number of civil and criminal actions and administrative proceedings. In addition to existing provisions accrued as of December 31, 2018 to account for ongoing proceedings, in future years Eni may incur significant losses in addition to the amounts already accrued in connection with pending or future legal proceedings due to: (i) uncertainty regarding the final outcome of each proceeding; (ii) the occurrence of new developments that management could not take into consideration when evaluating the likely outcome of each proceeding in order to accrue the risk provisions as of the date of the latest financial statements; (iii) the emergence of new evidence and information; and (iv) underestimation of probable future losses due to the circumstance that they are often inherently difficult to estimate. Certain legal proceedings and investigations in which Eni or its subsidiaries or its officers and employees are defendant involve the alleged breach of anti-bribery and anti-corruption laws and regulations and other ethical misconduct. Such proceedings are described in Note 27 to the 2018 Consolidated financial statements, under the heading "Legal Proceedings". Ethical misconduct and noncompliance with applicable laws and regulations, including noncompliance with anti-bribery and anti-corruption laws, by Eni, its officers and employees, its partners, agents or others that act on the Group's behalf, could expose Eni and its employees to criminal and civil penalties and could be damaging to Eni's reputation and shareholder value.

Risks from acquisitions

Eni is constantly monitoring the oil and gas market in search of opportunities to acquire individual assets or companies with a view of achieving its growth targets or complementing its asset portfolio. Acquisitions entail an execution risk – the risk that the acquirer will not be able to effectively integrate the purchased assets so as to achieve expected synergies. In addition, acquisitions entail a financial risk – the risk of not being able to recover the purchase costs of acquired assets, in case a prolonged decline in the market prices of oil and natural gas occurs. Eni may also incur unanticipated costs or assume unexpected liabilities and losses in connection with companies or assets it acquires. If the integration and financial risks related to acquisitions materialize, expected synergies from acquisition may fall short of management's targets and Eni's financial performance and shareholders' returns may be adversely affected.

Risks deriving from Eni's exposure to weather conditions

Significant changes in weather conditions in Italy and in the rest of Europe from year to year may affect demand for natural gas and some refined products. In colder years, demand for such products is higher. Accordingly, the results of operations of the Gas & Power segment and, to a lesser extent, the Refining & Marketing business, as well as the comparability of results over different periods may be affected by such changes in weather conditions.

Eni's crisis management systems may be ineffective

Eni has developed contingency plans to continue or recover operations following a disruption or incident. An inability to restore or replace critical capacity to an agreed level within an agreed period could prolong the impact of any disruption and could severely affect business, operations and financial results. Eni has crisis management plans and the capability to deal with emergencies at every level of its operations. If Eni does not respond or is not seen to respond in an appropriate manner to either an external or internal crisis, its business and operations could be severely disrupted with negative consequences on results of operations and cash flow.

Exposure to financial risk

Eni's business activities are exposed to financial risk, which includes exposure to market risk, including commodity price risk, interest rate risk and foreign currency risk, as well as liquidity risk, and credit risk.

Eni's primary source of exposure to financial risk is the volatility in commodity prices. Generally, the Group does not hedge its strategic exposure to the commodity risk associated with its plans to find and develop oil and gas reserves, volume of gas purchased under its long-term gas purchase contracts, which are not covered by contracted sales, its refining margins and other activities. The Group's risk management objectives in addressing commodity risk are to optimize the risk profile of its commercial activities by effectively managing economic margins and safeguarding the value of Eni assets. To achieve this, Eni engages in risk management activities seeking both to hedge Group's exposures and to profit from short-term market opportunities and trading.

Eni is engaged in substantial trading and commercial activities in the physical markets. Eni also uses financial instruments such as futures, options, Over-the-Counter forward contracts, market swaps and contracts for differences related to crude oil, petroleum products, natural gas and electricity in order to manage the commodity risk exposure. Eni also uses financial instruments to manage foreign exchange and interest rate risk.

The Group's approach to risk management includes identifying, evaluating and managing the financial risk using a top-down approach whereby the Board of Directors is responsible for establishing the Group risk management strategy and setting the maximum tolerable amounts of risk exposure. The Group's Chief Executive Officer is responsible for implementing the Group risk management strategy, while the Group's Chief Financial Officer is in charge of defining policies and tools to manage the Group's exposure to financial risk, as well as monitoring and reporting activities.

Various Group committees are in charge of defining internal criteria, guidelines and targets of risk management activities consistent with the strategy and limits defined at Eni's top level, to be used by the Group's business units, including monitoring and controlling activities. Although Eni believes it has established sound risk management procedures, trading activities involve elements of forecasting and Eni is exposed to the risks of market movements, of incurring significant losses if prices develop contrary to management expectations and of default of counterparties.

Exchange rate risk

Movements in the exchange rate of the euro against the U.S. dollar can have a material impact on Eni's results of operations. Prices of oil, natural gas and refined products generally are denominated in, or linked to, U.S. dollars, while a significant portion of Eni's expenses are incurred in euros. Accordingly, a depreciation of the U.S. dollar against the euro generally has an adverse impact on Eni's results of operations and liquidity because it reduces booked revenues by an amount greater than the decrease in U.S. dollar-denominated expenses and may also result in significant translation adjustments that impact Eni's shareholders' equity. The Exploration & Production segment is particularly affected by movements in the dollar versus the euro exchange rates as the U.S. dollar is the functional currency of a large part of its foreign subsidiaries and therefore movements in the U.S. dollar versus the euro exchange rate affect year-on-year comparability of results of operations and cash flows.

Susceptibility to variations in sovereign rating risk

Eni's credit ratings are potentially exposed to risk in reductions of sovereign credit rating of Italy. On the basis of the methodologies used by Standard & Poor's and Moody's, a potential downgrade of Italy's credit rating may have a potential knock-on effect on the credit rating of Italian issuers such as Eni and make it more likely that the credit rating of the debt instruments issued by the Company could be downgraded.

Interest rate risk

Interest on Eni's debt is primarily indexed at a spread to benchmark rates such as the Europe Interbank Offered Rate, "EURIBOR", and the London Interbank Offered Rate, "LIBOR". As a consequence, movements in interest rates can have a material impact on Eni's finance expense in respect to its debt. Additionally, spreads offered to the Company may rise in connection with variations in sovereign rating risks or company rating risks, as well as the general conditions of capital markets.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace in order to meet short-term financial requirements and to settle obligations. Such a situation would negatively affect the Group results of operations and cash flows as it would result in Eni incurring higher borrowing expenses to meet its obligations or, under the worst conditions, the inability of Eni to continue as a going concern. Global financial markets are volatile due to a number of macroeconomic risk factors, including the financial situation of certain hydrocarbons-exporting countries whose financial conditions have sharply deteriorated following the protracted downturn in crude oil prices. In the event of extended periods of constraints in the financial markets, or if Eni is unable to access the financial markets (including cases where this is due to Eni's financial position or market sentiment as to Eni's prospects) at a time when cash flows from Eni's business operations may be under pressure, Eni's ability to maintain Eni's long-term investment program may be impacted with a consequent effect on Eni's business prospects, results of operations and cash flows, and may impact shareholder returns, including dividends or share price.

The oil and gas industry is capital intensive. Eni makes and expects to continue to make substantial capital expenditures in its business for the exploration, development and production of oil and natural gas reserves. Over the next four years, the Company plans to invest in the business approximately €33 billion, approximately 50% of capital expenditures at the end of the four-year period refers to uncommitted projects, granting to the Group financial flexibility in case of sudden changes in the trading environment. In 2019, Eni expects to make capital expenditures of approximately €8 billion, in line with 2018. Historically, Eni's capital expenditures have been financed with cash generated by operations, proceeds from asset disposals, borrowings under its credit facilities and proceeds from the issuance of debt and bonds.

The actual amount and timing of future capital expenditures may differ materially from Eni's estimates as a result of, among other things, changes in commodity prices, available cash flows, lack of access to capital, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, and regulatory, technological and competitive developments.

Eni's cash flows from operations and access to capital markets are subject to a number of variables, including but not limited to:

- the amount of Eni's proved reserves;
- the volume of crude oil and natural gas Eni is able to produce and sell from existing wells;
- the prices at which crude oil and natural gas are sold;
- Eni's ability to acquire, find and produce new reserves; and
- the ability and willingness of Eni's lenders to extend credit or of participants in the capital markets to invest in Eni's bonds.

If revenues or Eni's ability to borrow decrease significantly due to factors such as a prolonged decline in crude oil and natural gas prices, Eni might have limited ability to obtain the capital necessary to sustain its planned capital expenditures. If cash generated by operations, cash from asset disposals, or cash available under Eni's liquidity reserves or its credit facilities is not sufficient to meet capital requirements, the failure to obtain additional financing could result in a curtailment of operations relating to development of Eni's reserves, which in turn could adversely affect its business, financial condition, results of operations, and cash flows and its ability to achieve its growth plans. These factors could also negatively affect shareholders' returns, including the amount of cash available for dividend distribution as well as the share price.

In addition, funding Eni's capital expenditures with additional debt will increase its leverage and the issuance of additional debt will require a portion of Eni's cash flows from operations to be used for the payment of interest and principal on its debt, thereby reducing its ability to use cash flows to fund capital expenditures and dividends.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay due amounts. Credit risks arise from both commercial partners and financial ones. In the last few years, the Group has experienced a level of counterparty default higher than in previous years due to the severity of the economic and financial downturn that has negatively affected several Group counterparties, customers and partners and to the fact that Italy, which is still the largest market to Eni's gas wholesale and retail businesses, has underperformed other OECD countries in terms of GDP growth. Management believes that the Gas&Power segment is particularly exposed to credit risk due to its large and diversified customer base, which includes a large number of medium and small-sized businesses and retail customers who have been particularly hit by the financial and economic downturn. Going forward, we expect that an uncertain macroeconomic outlook in Europe and Italy will pose a risk to the Company's ability to collect revenues in its retail gas and power business.

Eni's E&P business is significantly exposed to the credit risk because of the deteriorated financial outlook of many oil-producing countries due to a three-year long downturn in oil prices, which has negatively impacted petroleum revenues and cash reserves. Certain countries where Eni is engaging in oil&gas operations have yet to recover from the oil downturn. The financial difficulties of those countries have extended to state-owned oil companies and other national agencies who are partnering Eni in the execution of development projects of hydrocarbons reserves or who are the buyers of Eni's equity production in a number of oil&gas projects. These trends have limited Eni's ability to fully recover or to collect timely its trade or financing receivable or its investments towards those entities. For further information, see the paragraph "Political Considerations" above.

Eni believes that the management of doubtful accounts represents an issue to the Company, which will require management focus and commitment going forward. Eni cannot exclude the recognition of significant provisions for doubtful accounts in the future. In particular, management is closely monitoring exposure to the counterpart risk in its Exploration & Production due to the magnitude of the exposure at risk and to the long-lasting effects of the oil price downturn on its industrial partners.

Disruption to or breaches of Eni's critical IT services or information security systems could adversely affect the Group's activities.

The Group's activities depend heavily on the reliability and security of its information technology (IT) systems. The Group's IT systems, some of which are managed by third parties, are susceptible to being compromised, damaged, disrupted or shutdown due to failures during the process of upgrading or replacing software, databases or components, power or network outages, hardware failures, cyber-attacks (viruses, computer intrusions), user errors or natural disasters. The cyber threat is constantly evolving. Attacks are becoming more sophisticated with regularly renewed techniques while the digital transformation amplifies exposure to these cyber threats. The adoption of new technologies, such as the Internet of things (IoT) or the migration to the cloud, as well as the evolution of architectures for increasingly interconnected systems, are all areas where cyber security is a very important issue. The Group and its service providers may not be able to prevent third parties from breaking into the Group's IT systems, disrupting business operations or communications infrastructure through denial-of-service attacks, or gaining access to confidential or sensitive information held in the system. The Group, like many companies, has been and expects to continue to be the target of attempted cybersecurity attacks. While the Group has not experienced any such attack that has had a material impact on its business, the Group cannot guarantee that its security measures will be sufficient to prevent a material disruption, breach or compromise in the future.

As a result, the Group's activities and assets could sustain serious damage, services to clients could be interrupted, material intellectual property could be divulged and, in some cases, personal injury, property damage, environmental harm and regulatory violations could occur, potentially having a material adverse effect on the Group's financial condition, including its operating income and cash flow.

The United Kingdom leaving the European Union may affect the Group's results

On 23 June 2016, the UK held a referendum to decide on the UK's membership of the European Union. The UK vote was to leave the European Union. There are a number of uncertainties in connection with the future of the UK and its relationship with the European Union. The negotiation of the UK's exit terms is likely to take a number of years. Until the terms and timing of the UK's exit from the European Union are clearer, it is not possible to determine the impact that the referendum, the UK's departure from the European Union and/or any related matters may have on the business of the Issuer.

As such, no assurance can be given that such matters would not adversely affect the Company's business prospects, results of operations, cash flows and liquidity.

Item 4. INFORMATION ON THE COMPANY

History and development of the Company

Eni SpA with its consolidated subsidiaries engages in the exploration, development and production of hydrocarbons, in the supply and marketing of gas, LNG and power, in the refining and marketing of petroleum products, in the production and marketing of basic petrochemicals, plastics and elastomers and in commodity trading. Eni has operations in 67 countries and 31,701 employees as of December 31, 2018.

Eni, the former Ente Nazionale Idrocarburi, a public law agency, established by Law No. 136 of February 10, 1953, was transformed into a joint stock company by Law Decree No. 333 published in the Official Gazette of the Republic of Italy No. 162 of July 11, 1992 (converted into law on August 8, 1992, by Law No. 359, published in the Official Gazette of the Republic of Italy No. 190 of August 13, 1992). The Shareholders' Meeting of August 7, 1992 resolved that the company be called Eni SpA. Eni is registered at the Companies Register of Rome, register tax identification number 00484960588, R.E.A. Rome No. 756453. Eni is expected to remain in existence until December 31, 2100; its duration can however be extended by resolution of the shareholders.

The name of the agent of Eni in the United States is Giovan Battista Di Giovanni, Washington DC – USA 601, 13th street, NW 20005.

Eni's principal segments of operations are described below.

Eni's Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations, in 43 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Iraq, Indonesia, Ghana, Mozambique, Oman and United Arab Emirates. In 2018, Eni average daily production amounted to 1,732 KBOE/d on an available-for-sale basis. As of December 31, 2018, Eni's total proved reserves amounted to 7,153 mmBOE, which include subsidiary undertakings and Eni's share of reserves of equity-accounted and proportionally consolidated entities.

Eni's Gas & Power segment engages in the supply, trading and marketing of gas, LNG and electricity, international gas transport activities and commodity trading and derivatives. This segment also includes the activity of electricity generation that is ancillary to the marketing of electricity. In 2018, Eni's worldwide sales of natural gas amounted to 76.71 BCM, of which 39.03 BCM in Italy. Eni produces power at a number of operated gas-fired plants in Italy with a total installed capacity of 4.7 GW as of December 31, 2018. In 2018, electricity sold totalled 37.07 TWh. The LNG business includes the purchase and marketing of LNG worldwide, with a large incidence of equity LNG supplies. The Group serves the gas and power wholesale and retail markets in Italy and in a number of European markets. As at December 31, 2018 the Gas & Power segment had 9.2 million retail customers. The Gas & Power segment comprises results of the Group activities intended to manage commodity risk of asset-backed trading activities and proprietary trading. Furthermore, this activity includes the result of crude oil and products supply, trading and shipping.

Eni's Refining & Marketing and Chemical segment includes the result of the R&M business and of the chemicals business.

The R&M business engages in crude oil supply and refining and marketing of petroleum products in retail and wholesale markets mainly in Italy and in the rest of Europe, as well as in the petrochemical business. In 2018, processed volumes of crude oil and other feedstock, including renewable feedstock, amounted to 23.48 mmtonnes (of which traditional refinery throughputs were 23.23 mmtonnes and green refinery throughputs were 0.25 mmtonnes) and sales of refined products were 32.92 mmtonnes, of which 25.91 mmtonnes in Italy. Retail sales of refined products at Eni's service stations amounted to 8.39 mmtonnes in Italy and in the rest of Europe. In 2018, Eni's retail market shares in Italy through its "Eni" branded network of service stations was 24%.

In the Chemical business Eni, through its wholly-owned subsidiary Versalis, engages in the production and marketing of basic petrochemical products, plastics and elastomers. Versalis is developing the business of green chemicals. Activities are concentrated in Italy and in Europe. In 2018, production volumes of petrochemicals amounted to 9,483 ktonnes. The results of Versalis have been aggregated with those of R&M, in the reportable segment "R&M and Chemicals" because the two businesses exhibit similar economic characteristics.

Eni's registered head office is located at Piazzale Enrico Mattei 1, Rome, Italy (telephone number: +39-0659821).

Eni branches are located in:

- San Donato Milanese (Milan), Via Emilia, 1; and
- San Donato Milanese (Milan), Piazza Ezio Vanoni, 1.

Internet address: eni.com

A list of Eni's subsidiaries is provided in "Item 18 – Note 37 – Other information about investments – of the Notes on Consolidated Financial Statements".

Strategy

During the downturn in oil prices which lasted from the second half of 2014 to the end of 2017, the Company managed to reduce its cash neutrality – i.e. the level of Brent price at which cash flow from operating activities is able to fund capital expenditure and dividend payments – and to preserve a solid balance sheet. In 2018 we made substantial progress in delivering on our financial targets leveraging on a recovery in crude oil prices, which lasted ten months until October 2018, and on an improved underlying performance. We reported a better cash flow from operating activities and an improvement in the Group financial condition. These achievements were driven by our successful exploration activity which contributed to reserve replacement and cash generation by means of our dual exploration model, cost and capital discipline, reducing the time to market of reserves, growing profitably hydrocarbons production, restructuring our loss-making mid and downstream business that are currently generating structural positive results, pursuing integration across businesses and finally process simplification and streamlining. In 2018 we made substantial progress in enlarging the geographic reach of our asset portfolio and in rebalancing the business along the hydrocarbons "value chain" by making strategic acquisitions in the Middle East which comprised exploration and development properties in the UAE and elsewhere in the region and a deal under completion to acquire a 20% interest in the Ruwais refining complex in the UAE. This deal is expected to be finalized by year end. See the paragraph below for more details about our expansion in the Middle East.

Looking forward we plan to enhance value generation across all our businesses by developing the growth opportunities associated with the purchased assets in the Middle East and by maturing the other grow initiatives under execution. The strategic guidelines going forward are:

- Growing oil&gas production with improving returns leveraging on the organic developments of our discoveries and full ramp up at our core producing fields and fields started in 2018;
- Retaining a strong focus on exploration activities to ensure reserve replacement, diversification of geographies and opportunities to deploy our dual exploration model;
- Strengthening results and cash generation in our mid and downstream businesses through contract renegotiations, selective growth initiatives, improvement of plant reliability, higher flexibility in raw materials and feedstock, innovation in products and services, and cost efficiencies;
- Pursuing margin and growth opportunities through enhanced business integration;
- Financial discipline;
- Increased digitalization to support operations efficiency;
- Reducing the carbon footprint of the Company by means of increasing efficiency and developing the green businesses and the industrial initiatives intended to promote a circular economy.

Implementation of this strategy will be supported by a capital plan of €33 billion, approximately 77% of which will be destined to finding and developing hydrocarbons reserves.

We believe that the action plan we have designed for the next four-year period 2019 – 2022 at the Company's Brent scenario of $62 in 2019 subsequently increasing to our long-term case of $70 will improve the Company's profitability and cash generation reducing further our cash neutrality. We remain committed to our progressive distribution policy in line with the expected growth in underlying earnings and cash flow. See Item 5 – Management Expectations of Operation.

Strategy for a low-carbon environment

Our path to decarbonization has four main drivers that concern both our core business activities and new energy perspectives:

- The first is to retain a portfolio of oil&gas projects that we believe are resilient to a low carbon scenario
- The second is our action plan to lower CO_2 emissions in all our operations, particularly to reduce the energy intensity at our exploration and production activities and improve energy efficiency across all business lines;
- Thirdly, we intend to grow our business of power generation produced by renewable sources, to develop the forestry business, to increase production of bio-fuels and to execute several industrial projects designed to recycle organic waste and other civil waste aiming at producing energy or raw materials to produce bio-fuels or bio-chemicals as well as to revitalize dismissed or decommissioned industrial sites;
- Finally, R&D will play a key role in our decarbonization strategy.

Our portfolio of oil and gas properties features a large weight of natural gas, the least GHG-emitting fossil energy source, which represented approximately 49% of Eni's production in 2018 on an available-for-sale basis; as of 31 December 2018, gas reserves represented approximately 50% of Eni's total proved reserves of its subsidiary undertakings and joint ventures. The other pillar of our resilient portfolio of oil&gas properties is the high incidence of conventional projects, developed through phases and with low CO_2 intensity. We estimate that the new oil&gas projects under execution, which will attract some 45% of the projected development expenditures in the next four-year plan, have a price breakeven of around 25 $ per barrel. We believe that those elements of our portfolio will mitigate the risk of stranded reserves going forward due to risks of lower hydrocarbons demand in response to stricter global environmental constraints and regulations and increasing public sensitivity to the issue of global warming. Eni's portfolio exposure to those risks is reviewed annually against changing GHG regulatory regimes and physical conditions to identify emerging risks. To test the resilience of new projects, Eni assesses potential costs associated with GHG emissions when evaluating all new capital projects. New projects' internal rates of return are stress-tested against two sets of assumptions: i) Eni's management estimation of a cost per ton of carbon dioxide (CO_2) equivalent of 40 $/tonnes in real terms 2015, which is applied to the total GHG emissions of each capital project, while retaining the management scenario for hydrocarbons prices; and ii) the hydrocarbon prices and cost of CO_2 emissions adopted in the International Energy Agency (IEA) Sustainable Development Scenario "IEA SDS". This stress test is performed on a regular basis, to monitor the progress of each project. The review performed at the end of 2018 indicated that the internal rates of return of Eni's ongoing projects in aggregate should not be substantially affected by a carbon pricing mechanism. The project development process features a number of checks that may require the development of detailed GHG and energy management plans. The majority of the projects have GHG intensity targets that allow them under current assumptions to compete in a more CO_2 regulated future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when the economic conditions imposed by new regulation would make these investments commercially compelling.

Furthermore, management performed a review of the recoverability of the book values of the Company's oil & gas assets under the assumptions set forth in the IEA SDS. This review covered all of the oil & gas cash generating unit (CGUs) that are regularly tested for impairment in accordance to IAS 36. The IEA SDS sets out an energy pathway consistent with the goal of achieving universal energy access by 2030 and of reducing by a half energy-related CO_2 emissions and of reducing air pollution by 2040, compared to projections with no further policy action. The IEA SDS forecasts that demand for oil is going to peak in 2020. The hydrocarbons pricing assumptions of the IEA SDS scenario are more optimistic than Eni's scenario, particularly the IEA SDS scenario projects crude oil prices to be much higher than Eni's crude oil pricing assumptions. On the other hand, CO_2 emissions costs under the IEA SDS assumptions will show a strong uptrend consistent with the goal of encouraging the adoption of low carbon technologies. Such CO_2 emissions costs as estimated by the IEA SDS would reach up to 140 $ per ton in real terms in 2040, which is higher than Eni's CO_2 pricing trends and assumptions for the medium-long term. Nevertheless, the sensitivity test performed at Eni's oil&gas CGUs under the IEA SDS assumptions indicated the resiliency of Eni's asset portfolio in terms of carrying amounts and fair value, because the loss of value that would result from the higher CO_2 costs assumed by the IEA SDS (in comparison to Eni's projections) is outweighed by higher assumptions for crude oil prices assumed in the IEA SDS scenario.

In October 2018 the Intergovernmental Panel on Climate Change (IPCC) stated, in a new report, that in order to limit global warming to 1.5°C, the world economy would need to undertake a deeper and complex transformation. We recognize that meeting this challenge in the next decades requires an even more rapid escalation, both in term of size and speed, of changes than were foreseen in the Paris Agreement. Currently, this scenario has yet to be complemented by a full set of pricing and other operating assumptions, which once available from the IPCC or other sources will be deeply analyzed by the Company for the purpose of updating stress-testing models and methodologies.

To strengthen the resiliency of our oil&gas portfolio, we are fully committed to reduce the energy intensity at our oil and gas projects. In 2018 we reduced the energy intensity in our E&P business to 21.44 tonnes of CO_2 equivalent per thousand of BOE, down by 6% y-o-y and by 20% from 2014 levels. This measure relates to gross operated production. By 2030 we are targeting to achieve net zero emissions in our upstream business (on equity basis) by:

- Increasing efficiency to minimize direct upstream CO_2 emissions. As part of this target by 2025 we plan to eliminate gas process flaring and reduce methane emissions by 80%; and
- offsetting residual upstream emissions through large forestry projects.

Going forward, our de-carbonization strategy will be underpinned by the development of the business of power generation from renewable sources, growth at our green business lines and implementation of a number of industrial projects designed to promote the circular economy. These projects will attract some €3 billion, or 9% of the Group planned capex for the four-year period 2019 – 2022, including projects designed to reduce gas flaring and improve energy efficiency across all business lines.

The renewable power generation business will comprise an expansion plan of generation capacity fueled by photovoltaic or wind power, targeting a total installed capacity of 1.6 GW by 2022 through the execution of more than sixty projects. The green business involves the production of bio-fuels and bio-chemicals at our green refineries and chemical hubs. This business will be enhanced due to the completion of the second upgrading phase at our Venice bio-refinery and the start-up of the Gela bio-refinery which are designed to process vegetable feedstock to produce high-quality automotive fuels. The two refineries are planned to produce 1 mmtonnes per year of green-diesel by 2021, making Eni one of the top producers in Europe. The green business at our chemical subsidiary Versalis is expected to ramp up due to the integration of assets acquired in 2018. Finally, we plan to implement a number of initiatives intended to promote the circular economy, as in the case of projects to convert organic waste and plastic waste into feedstock for the production of bio-fuels and bio-chemicals. Finally, management has established a long-term ambition of accomplishing the carbon neutrality leveraging on the following lines of action: i) direct emission reduction, maximizing efficiency in operations and promoting a shift in the energy mix; ii) development of wide forestry initiatives to increase carbon offset; iii) a continuing growth in projects designed to promote the circular economy by recycling waste and by revitalizing decommissioned assets; iv) advances in R&D potentially leading to break-through technologies for example in the fields of the sequestration of CO_2 and of nuclear fusion.

Significant business and portfolio developments

- March 2019 – In Italy, Eni has sucessfully installed and started up the Inertial Sea Wawe Energy Converter (ISWEC) production unit to convert energy generated by waves into electricity.
- March 2019 – Eni announced a new gas discovery, under evaluation, in the Nour exploration license, offshore Egypt.
- March 2019 – Eni farmed out to Qatar Petroleum a 30% stake in the Tarfaya Area, comprising 12 exploration blocks, offshore Morocco. The agreement is subject to the authorization by the Moroccan authorities.
- March 2019 – Eni, following the oil discovery in the Afoxé prospect in December 2018, announced a new oil discovery in the Agogo exploration prospect located in the Block 15/06, offshore Angola.
- March 2019 – Eni farmed out to Qatar Petroleum a 25.5% participating interest in block A5-A, offshore Mozambique. The agreement is subject to the authorization by the Mozambican authorities.. Once the farm-out is completed, Eni will remain operator and its interest in the asset will decrease to 34%.
- February 2019 – The Egyptian Authorities granted Eni two exploration blocks onshore Egypt, in the Western Desert and onshore Nile Delta: South East Siwa (Eni's interest 100%) and West Sherbean (Eni's interest 50%, operator; BP 50%).

- February 2019 – Finalized the acquisition of a construction-ready solar photovoltaic project near Katherine, in the Northern Territory of the Australia, with an installed capacity of 33.7 MW. The plant will be equipped with a battery storage system and, once into operation, it will avoid around 63,000 tonnes/year of CO_2 equivalent emissions.
- January 2019 – Eni signed with Pertamina, the Indonesian state-owned energy company, two agreements to expand the relationship into green refinery and discuss collaboration opportunities in low carbon products and renewable energies development, in particular in waste transformation processes and biomass valorization processes.
- January 2019 – Agreement with Abu Dhabi National Oil Company ("ADNOC") for the acquisition of a 20% interest in the ADNOC Refining company, which owns the refining complexes of Ruwais and Abu Dhabi, with an overall capacity of more than 900 kbbl/d. The total consideration of the deal amounts to $3.3 billion, net of acquired debt and possible price adjustments at the closing date. Additionally, the agreement includes the creation of a joint venture engaged in trading activities, participated by Eni with a 20% interest.
- January 2019 – Eni started a new production well in the Vandumbu field in Block 15/06, offshore Angola, where production commenced in December 2018. The ramp-up is expected to be completed in 2019.
- January 2019 – Vår Energi, the newly constituted entity jointly controlled by Eni and HitecVision, in the Norwegian upstream sector, was awarded thirteen exploration licenses. The company will be operator of 4 licenses and partner of 9 licenses. In 2018 Eni finalized the business combination between Eni Norge and Point Resources, fully controlled by Eni and HitecVision respectively, leading to the creation of Vår Energi, an equity-accounted joint venture (Eni's interest 69.6%) that will develop the activities of the two partners in Norway targeting a production plateau of 250 kboe/d in 2023.
- January 2019 – Eni was awarded seven exploration licenses in onshore/offshore areas in the Middle East: two licenses in Abu Dhabi, one in Oman, one in the Kingdom of Bahrain and three in the Sharjah Emirate.
- December 2018 – Signed a preliminary agreement to acquire a 70% interest and the operatorship of the Oooguruk oil field, in Alaska. Eni already owns the remaining 30% interest. The agreement has been finalized in 2019.
- December 2018 – Significant progress was made towards the final investment decision (FID) of the first phase of the Rovuma LNG project, which contemplates the construction of two LNG trains, each with a capacity of 7.6 mmtonnes/y and obtaining the project financing. After the submission and reviewing of the development plan (PoD) of the project from the authorities, the co-venturers of Area 4 secured long-term agreements for the purchase of LNG volumes. The final investment decision is expected in 2019 and the production is expected to commence in 2024.
- December 2018 – Started up at the Gela site, in Sicily, a pilot plant for recycling and transforming the organic fraction of solid waste produced by households and civil buildings into bio-oil, through proprietary waste to-fuel technology.
- December 2018 – Announced the Merakes East Gas discovery, offshore Indonesia.
- December 2018 – Made the final investment decision at the Merakes Gas Development Project in Indonesia following the approval received by the Minister of Energy of Indonesia. The PoD will leverage the expected synergies with the existing infrastructures of the close Jangkrik gas field producing through a FPU.
- December 2018 – Signed an agreement with Qatar Petroleum for the divestment of a 35% interest in Area 1 discoveries, offshore Mexico, while retaining the operatorship. The agreement is subject to the authorization by the Mexican authorities. The FID project was made at the same time. The start of the pilot project is expected in 2019.
- December 2018 – Farmed out of part of Eni's interest in the Nour license in Egypt to BP (25%) and Mubadala (20%). Eni will retain a 40% interest and the asset operatorship.
- In 2018 Eni, as part of its commitment in circular economy, launched a number of partnerships with some Italian municipalities, Vatican City and multi-utility companies operating in waste treatment and local public transport (in Taranto, Turin, Venice, Rome and in some municipalities of Emilia Romagna) for the exploitation of civil waste and organic raw materials by using them as feedstock to produce energy resources such as biofuels.
- November 2018 – Completed the construction of a photovoltaic plant with a capacity of 10 MW (Eni's share 5 MW), close to the oil field Bir Rebaa Northin Algeria, jointly operated by Sonatrach and Eni.

- November 2018 – Awarded by the Abu Dhabi National Oil Company (ADNOC) a 25% interest in the Ghasha concession, a large offshore gas project. Eni will retain the technical leadership with expected start-up by the end of 2022 and a projected production plateau at 1.5 bcf/d.
- November 2018 – Versalis and Mazrui Energy Service signed an agreement to establish a joint venture for the commercialization of innovative chemicals for the Oil & Gas industry in the Middle East.
- November 2018 – Eni and Sonangol signed an amendment of Block 15/06 Production Sharing Contract which defined a new block extension.
- November 2018 – Eni and Lukoil signed a farm-out agreement for the transfer of participating interests in three exploration licenses in Mexico's shallow waters. Eni will give Lukoil a 20% stake in the Production Sharing Contracts (PSC) in both Area 10 and Area 14, and will acquire a 40% stake in Lukoil's PSC for Area 12. The agreement is subject to the approval by the Mexican authorities.
- November 2018 – Finalized the acquisition of the Italian Mossi & Ghisolfi Group, engaged in the field of bio-chemicals. The acquired operation includes assets and resources related to development activities, industrialization, licensing of technologies and bio-chemical processes based on the use of renewable resources, especially biomass.
- October 2018 – Eni, Sonatrach and Total signed two agreements which include an exclusive partnership for offshore exploration in Algeria in a virtually unexplored geological province.
- October 2018 – Eni and Sonatrach signed an agreement that will see Eni take a 49% stake in three oil concessions in the onshore North Berkine basin, located in the Algerian desert. Production is expected to start by the end of 2020.
- October 2018 – Eni announced a new oil discovery in the western Barents Sea within license PL 532 in Norway.
- October 2018 – Eni, BP and NOC signed an agreement to resume exploration in Libya. The aim for Eni is to obtain a 42.5% participating interest and the assignment of the operatorship in two onshore and one offshore contractual areas in Libya.
- October 2018 – Eni announced the successful drilling of Cape Vulture appraisal well in the license PL128/PL128D in the Norwegian Sea.
- September 2018 – Eni and GE Renewable Energy signed an agreement for the supply of onshore wind turbines for the Eni-operated Badamsha wind farm project in Kazakhstan, with a target capacity of 50 MW. The FID of the Badamsha project was made in June 2018. The commercial operation date and the connection to the grid is expected by the end of 2019.
- September 2018 – Started up a new elastomer plant in Ferrara, mainly supplying specialties to the automotive industry;
- September 2018 – Eni reached 2.1 bcf/d production target at Zohr field, with the start-up of the fifth treatment unit, in just few months since the first gas (December 2017), the second and third production (April 2018 and May 2018, respectively) and one year before the schedule of the PoD. Expected to reach the production plateau (2.7 bcf/d) in 2019.
- August 2018 – Gas discovery in Egypt at the East Obayed concession, in the Egyptian Western Desert in proximity of producing assets.
- August 2018 – Eni acquired 124 licenses onshore in the Eastern North Slope of Alaska.
- August 2018 – Approved a ten-year extension of the Nile Delta Concession Agreement and a five-year extension of the Ras Qattara Concession Agreement in Egypt.
- August 2018 – Eni was awarded the Nour exploration license in the gas-rich area of the East Nile Delta Basin in the Egyptian territorial waters of the Mediterranean Sea.
- August 2018 – Approved the PoD for the discoveries of Amoca, Miztón and Tecoalli, located in Area 1 (Eni 100%), in Mexico. Early production phase planned in 2019 and full field production will start in 2021.
- July 2018 – Announced another oil discovery in the South West Meleiha license, in the Egyptian Western Desert.
- July 2018 – Started production at the Bahr Essalam Phase 2 project, offshore in Libya.
- July 2018 – Eni started gas production from OCTP Project, deep offshore Ghana. The field will provide 180 mmscf/d for at least 15 years.
- June 2018 – Eni announced a new oil discovery in Block 15/06, in the Kalimba exploration prospect, in Angola's deep offshore.
- June 2018 – Eni divested to INA its upstream activities offshore Croatia. The transaction closed by year end.

- June 2018 – Eni finalized the divestment of a 10% stake in the Shorouk concession, offshore Egypt, to Mubadala Petroleum. Expected production plateau of 2.7 bcf/d by the end of 2019 (Eni's interest 50%, Rosneft 30%, BP 10% and Mubadala Petroleum 10%).
- May 2018 – Eni announced an oil discovery in the South West Meleiha license, in the Egyptian Western Desert.
- May 2018 – Eni was awarded a 100% participating interest in the East Ganal Exploration Block in the Kutei Basin in Indonesia.
- April 2018 – Eni and Sonatrach signed agreements to extend their long-dated partnership and to continue their collaboration in the R&D sector. The key feature of the deal was the launch of a large exploration and development program in the Berkine basin.
- March 2018 – Eni was awarded an Exploration & Production license in the Block 28 located in the Cuenca Salina Basin, offshore Mexico, with its partner Lukoil (Eni's interest 75%).
- March 2018 – Eni and Sonangol started oil production at the Ochigufu project, in Block 15/06 in Angola deep offshore. In May, the production ramp-up at the field was completed, allowing the operated production from the Block to stabilize around 150,000 barrels/d and in line with the goal of adding 54,000 barrels/d to the block's production by 2019. The field added 25 KBBL to Eni's current production levels.
- March 2018 – Eni signed a license agreement with Zhejiang Petrochemicals for the license for the construction of two refining lines based on Eni Slurry Technology (EST). The two production lines will have a refining capacity of 3 mmtonnes per year and they will be built as part of a project for the construction of a new refinery with a capacity of 40 mmtonnes per year. Start-up is planned for 2020.
- March 2018 – Eni signed in Abu Dhabi two Concession Agreements for the acquisition of a 5% stake in the Lower Zakum offshore oil field and of a 10% stake in the oil, condensate and gas offshore fields of Umm Shaif and Nasr, for a total participation fee of about $875 million and a contractual term of 40 years. Lower Zakum, located about 65 kilometers off the coast of Abu Dhabi, has a target production of 450 KBBL/d. Umm Shaif and Nasr, located about 135 kilometers from the coast of Abu Dhabi, have a target production of 460 KBBL/d.
- March 2018 – Eni signed agreements with Commonwealth Fusion Systems LLC (CFS) and the Massachusetts Institute of Technology to acquire an equity stake in CFS for the industrial development of the fusion power generation technology. Eni will support CFS to develop the first commercial power plant producing energy by fusion, a safe, sustainable, virtually inexhaustible source without any emission of pollutants and greenhouse gases. Eni acquired a significant share in the company with an initial investment of $50 million.
- February 2018 – Eni's subsidiary Versalis and Bridgestone Americas (Bridgestone) signed a partnership agreement to develop a technology platform to commercialize guayule in the agricultural, sustainable-rubber and renewable-chemical sectors. The partnership combines Versalis' core strengths in guayule research, commercial-scale process engineering and market development for renewables with Bridgestone's leadership position in guayule agriculture and production technologies.
- February 2018 – Eni signed two Exploration and Production Agreements (EPA) with the Republic of Lebanon covering Blocks 4 and 9, in the deep waters. Eni will retain a 40% interest in both blocks.
- February 2018 – Exploration activities yielded positive results with the Calypso 1 gas discovery in Block 6 (Eni operator with a 50% interest), offshore Cyprus.
- February 2018 – Eni and its partner Qatar Petroleum were awarded rights to Block 24 located in in the deep waters of the Cuenca Salina Basin in Mexico. Eni will retain the operatorship with a 65% working interest.
- January 2018 – A licensing agreement was signed with Sinopec, a big refining company, for the use of the Eni Slurry proprietary conversion Technology (EST). Eni will provide Sinopec with the basic engineering project related to the construction of a refining plant based on the EST that is able to fully transform refining residues into high-quality light products.

BUSINESS OVERVIEW

Exploration & Production

Eni's Exploration & Production segment engages in oil and natural gas exploration and field development and production, as well as LNG operations, in 43 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Iraq, Indonesia, Ghana, Mozambique, Oman and the United Arab Emirates. In 2018, Eni average daily production amounted to 1,732 KBOE/d on an available-for-sale basis. As of December 31, 2018, Eni's total proved reserves amounted to 7,153 mmBOE; proved reserves of subsidiaries totaled 6,356 mmBOE; Eni's share of reserves of equity-accounted entities was 797 mmBOE.

"Eni's strategy and short-to-medium term targets in its Exploration & Production segment are disclosed in Item 5 – Management's expectations of operations."

Disclosure of reserves

Overview

The Company has adopted comprehensive classification criteria for the estimate of proved, proved developed and proved undeveloped oil&gas reserves in accordance with applicable U.S. Securities and Exchange Commission (SEC) regulations, as provided for in Regulation S-X, Rule 4-10. Proved oil&gas reserves are those quantities of liquids (including condensates and natural gas liquids) and natural 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, 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.

Oil and natural gas prices used in the estimate of proved reserves are obtained from the official survey published by Platt's Marketwire, except when their calculation derives from existing contractual conditions. Prices are 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. Prices include consideration of changes in existing prices provided only by contractual arrangements.

Engineering estimates of the Company's oil&gas reserves are inherently uncertain. Although authoritative guidelines exist regarding engineering criteria that have to be met before estimated oil&gas reserves can be designated as "proved", the accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and evaluation. Consequently, the estimated proved reserves of oil and natural gas may be subject to future revision and upward and downward revisions may be made to the initial booking of reserves due to analysis of new information.

Proved reserves to which Eni is entitled under concession contracts are determined by applying Eni's share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right. Proved reserves to which Eni is entitled under PSAs are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (Cost Oil) and recognize the Profit Oil set contractually (Profit Oil). A similar scheme applies to service contracts.

Reserves governance

Eni retains rigorous control over the process of booking proved reserves, through a centralized model of reserves governance. The Reserves Department of the Exploration & Production segment is in charge of: (i) ensuring the periodic certification process of proved reserves; (ii) continuously updating the Company's guidelines on reserves evaluation and classification and the internal procedures; and (iii) providing training of staff involved in the process of reserves estimation.

Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which stated that those guidelines comply with the SEC rules[1]. D&M has also stated that the Company guidelines provide reasonable interpretation of facts and circumstances in line with generally accepted practices in the industry whenever SEC rules may be less precise. When participating in exploration and production activities operated by other entities, Eni estimates its share of proved reserves on the basis of the above guidelines.

The process for estimating reserves, as described in the internal procedure, involves the following roles and responsibilities: (i) the business unit managers (geographic units) and Local Reserves Evaluators (LRE) are in charge with estimating and classifying gross reserves including assessing production profiles, capital expenditure, operating expenses and costs related to asset retirement obligations; (ii) the petroleum engineering department and the operations unit at the head office verify the production profiles of such properties where significant changes have occurred and operating expenses, respectively; (iii) geographic area managers verify the commercial conditions and the progress of the projects; (iv) the Planning and Control Department provides the economic evaluation of reserves; and (v) the Reserves Department, through the Headquarter Reserves Evaluators (HRE), provides independent reviews of fairness and correctness of classifications carried out by the above-mentioned units and aggregates worldwide reserves data.

The head of the Reserves Department attended the "Università degli Studi di Milano" and received a Master of Science degree in Physics in 1988. He has more than 30 years of experience in the oil&gas industry and more than 20 years of experience in evaluating reserves.

Staff involved in the reserves evaluation process fulfils the professional qualifications requested by the role and complies with the required level of independence, objectivity and confidentiality in accordance with professional ethics. Reserves Evaluators qualifications comply with international standards defined by the Society of Petroleum Engineers.

Reserves independent evaluation

Eni has its proved reserves audited on a rotational basis by independent oil engineering companies[2]. The description of qualifications of the persons primarily responsible for the reserves audit is included in the third-party audit report[3]. In the preparation of their reports, independent evaluators rely upon information furnished by Eni, without independent verification, with respect to property interests, production, current costs of operations and development, sales agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. These data, equally used by Eni in its internal process, include logs, directional surveys, core and PVT (Pressure Volume Temperature) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies, technical analysis relevant to field performance, development plans, future capital and operating costs.

In order to calculate the net present value of Eni's equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements and other pertinent information are provided by Eni to third-party evaluators. In 2018, Ryder Scott Company, DeGolyer and MacNaughton and Societé Generale de Surveillance (SGS) provided an independent evaluation of approximately 26% of Eni's total proved reserves at December 31, 2018[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2016-2018 three-year period, 95% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2018, the M'Boundi field in Congo was the main Eni property, which did not undergo an independent evaluation in the last three years.

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1 See "Item 19 – Exhibits" in the Annual Report on Form 20-F 2009.
2 From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott. In 2018, the SGS company also provided an independent certification.
3 See "Item 19 – Exhibits".
4 Includes Eni's share of proved reserves of equity-accounted entities.
5 See "Item 19 – Exhibits".

Summary of proved oil and gas reserves

The tables below provide a summary of proved oil and gas reserves of the Group companies and its equity-accounted entities by geographic area for the three years ended December 31, 2018, 2017 and 2016.

HYDROCARBONS (mmBOE)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries[1]										
Dec. 31, 2018	**428**	**106**	**1,022**	**1,246**	**1,361**	**1,066**	**700**	**302**	**125**	**6,356**
developed	336	99	582	764	895	925	403	170	87	4,261
undeveloped	92	7	440	482	466	141	297	132	38	2,095
Dec. 31, 2017	**422**	**525**	**1,052**	**1,078**	**1,436**	**1,150**	**427**	**203**	**137**	**6,430**
developed	350	360	532	463	856	891	238	176	101	3,967
undeveloped	72	165	520	615	580	259	189	27	36	2,463
Dec. 31, 2016	**354**	**426**	**1,139**	**1,293**	**1,317**	**1,221**	**491**	**227**	**145**	**6,613**
developed	287	374	605	352	809	966	175	205	111	3,884
undeveloped	67	52	534	941	508	255	316	22	34	2,729
Equity-accounted entities[2]										
Dec. 31, 2018		**363**	**14**		**68**			**352**		**797**
developed		205	14		17			347		583
undeveloped		158			51			5		214
Dec. 31, 2017			**14**		**75**		**1**	**470**		**560**
developed			14		20		1	359		394
undeveloped					55			111		166
Dec. 31, 2016			**14**		**82**		**2**	**779**		**877**
developed			14		26		2	349		391
undeveloped					56			430		486
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	**428**	**469**	**1,036**	**1,246**	**1,429**	**1,066**	**700**	**654**	**125**	**7,153**
developed	336	304	596	764	912	925	403	517	87	4,844
undeveloped	92	165	440	482	517	141	297	137	38	2,309
Dec. 31, 2017	**422**	**525**	**1,066**	**1,078**	**1,511**	**1,150**	**428**	**673**	**137**	**6,990**
developed	350	360	546	463	876	891	239	535	101	4,361
undeveloped	72	165	520	615	635	259	189	138	36	2,629
Dec. 31, 2016	**354**	**426**	**1,153**	**1,293**	**1,399**	**1,221**	**493**	**1,006**	**145**	**7,490**
developed	287	374	619	352	835	966	177	554	111	4,275
undeveloped	67	52	534	941	564	255	316	452	34	3,215

(1) Include Eni's share of reserves held by a joint-operation in Mozambique which is proportionally consolidated in the Group consolidated financial statements in accordance to IFRS.

(2) Reserves volumes of the Rest of Europe area, in 2018, are affected by the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

LIQUIDS (mmBBL)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Dec. 31, 2018	**208**	**48**	**493**	**279**	**718**	**704**	**476**	**252**	**5**	**3,183**
developed	156	44	317	153	551	587	252	143	5	2,208
undeveloped	52	4	176	126	167	117	224	109		975
Dec. 31, 2017	**215**	**360**	**476**	**280**	**764**	**766**	**232**	**162**	**7**	**3,262**
developed	169	219	306	203	546	547	81	144	5	2,220
undeveloped	46	141	170	77	218	219	151	18	2	1,042
Dec. 31, 2016	**176**	**264**	**454**	**281**	**809**	**767**	**307**	**163**	**9**	**3,230**
developed	132	228	287	205	507	556	124	143	8	2,190
undeveloped	44	36	167	76	302	211	183	20	1	1,040
Equity-accounted entities[1]										
Dec. 31, 2018		**297**	**11**		**12**			**37**		**357**
developed		154	11		8			32		205
undeveloped		143			4			5		152
Dec. 31, 2017			**12**		**12**			**136**		**160**
developed			12		6			25		43
undeveloped					6			111		117
Dec. 31, 2016			**13**		**15**			**140**		**168**
developed			13		8			22		43
undeveloped					7			118		125
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	**208**	**345**	**504**	**279**	**730**	**704**	**476**	**289**	**5**	**3,540**
developed	156	198	328	153	559	587	252	175	5	2,413
undeveloped	52	147	176	126	171	117	224	114		1,127
Dec. 31, 2017	**215**	**360**	**488**	**280**	**776**	**766**	**232**	**298**	**7**	**3,422**
developed	169	219	318	203	552	547	81	169	5	2,263
undeveloped	46	141	170	77	224	219	151	129	2	1,159
Dec. 31, 2016	**176**	**264**	**467**	**281**	**824**	**767**	**307**	**303**	**9**	**3,398**
developed	132	228	300	205	515	556	124	165	8	2,233
undeveloped	44	36	167	76	309	211	183	138	1	1,165

(1) Reserves volumes of the Rest of Europe area, in 2018, are affected by the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

NATURAL GAS (BCF)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries[1]										
Dec. 31, 2018	**1,199**	**320**	**2,890**	**5,275**	**3,506**	**1,989**	**1,217**	**277**	**651**	**17,324**
developed	980	300	1,447	3,331	1,871	1,846	822	154	452	11,203
undeveloped	219	20	1,443	1,944	1,635	143	395	123	199	6,121
Dec. 31, 2017	**1,131**	**896**	**3,145**	**4,351**	**3,660**	**2,108**	**1,065**	**225**	**709**	**17,290**
developed	987	771	1,233	1,421	1,693	1,878	862	171	519	9,535
undeveloped	144	125	1,912	2,930	1,967	230	203	54	190	7,755
Dec. 31, 2016	**977**	**878**	**3,738**	**5,520**	**2,767**	**2,485**	**1,003**	**353**	**741**	**18,462**
developed	845	801	1,732	799	1,651	2,239	280	338	559	9,244
undeveloped	132	77	2,006	4,721	1,116	246	723	15	182	9,218
Equity-accounted entities[2]										
Dec. 31, 2018		**360**	**14**		**310**			**1,716**		**2,400**
developed		276	14		57			1,716		2,063
undeveloped		84			253					337
Dec. 31, 2017			**14**		**349**			**1,819**		**2,182**
developed			14		83			1,819		1,916
undeveloped					266					266
Dec. 31, 2016			**15**		**368**		**4**	**3,484**		**3,871**
developed			15		104		4	1,782		1,905
undeveloped					264			1,702		1,966
Consolidated subsidiaries and equity accounted entities										
Dec. 31, 2018	**1,199**	**680**	**2,904**	**5,275**	**3,816**	**1,989**	**1,217**	**1,993**	**651**	**19,724**
developed	980	576	1,461	3,331	1,928	1,846	822	1,870	452	13,266
undeveloped	219	104	1,443	1,944	1,888	143	395	123	199	6,458
Dec. 31, 2017	**1,131**	**896**	**3,159**	**4,351**	**4,009**	**2,108**	**1,065**	**2,044**	**709**	**19,472**
developed	987	771	1,247	1,421	1,776	1,878	862	1,990	519	11,451
undeveloped	144	125	1,912	2,930	2,233	230	203	54	190	8,021
Dec. 31, 2016	**977**	**878**	**3,753**	**5,520**	**3,135**	**2,485**	**1,007**	**3,837**	**741**	**22,333**
developed	845	801	1,747	799	1,755	2,239	284	2,120	559	11,149
undeveloped	132	77	2,006	4,721	1,380	246	723	1,717	182	11,184

(1) Include Eni's share of reserves held by a joint-operation in Mozambique which is proportionally consolidated in the Group consolidated financial statements in accordance to IFRS.

(2) Reserves volumes of the Rest of Europe area, in 2018, are affected the merger agreement that provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest.

Proved reserves of natural gas liquids are immaterial to the Group operations.

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 148 mmBOE as of December 31, 2018 (178 and 212 mmBOE as of December 31, 2017 and 2016, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			Equity-accounted entities		
(mmBOE)	2018	2017	2016	2018	2017	2016
Additions to proved reserves	772	969	1,254	(99)	(285)	(10)
Purchases of minerals-in-place	332	2		363		
Sales of minerals-in-place	(528)	(523)		(1)		
Total additions to proved reserves	**576**	**448**	**1,254**	**263**	**(285)**	**(10)**
Production for the year[(a)]	**(650)**	**(631)**	**(616)**	**(26)**	**(32)**	**(28)**

(a) The difference compared to production sold of 625.0 mmBOE (608.6 mmboe in 2016 and 622.3 mmboe in 2017) reflected hydrocarbons volumes of 43.5 mmBOE consumed in operations (32.1 mmBOE in 2016 and 35.2 mmBOE in 2017), changes in inventories and other factors.

	Subsidiaries and equity-accounted entities		
(%)	2018	2017	2016
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	124	25	193
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, organic	100	103	193

Eni's proved reserves as of December 31, 2018 totaled 7,153 mmBOE (liquids 3,540 mmBBL; natural gas 19,724 BCF). Eni's proved reserves reported an increase of 163 mmBOE, or 2.3%, from December 31, 2017 due to progress made in the year in exploring for and developing new reserves and property acquisitions net of property sales. Portfolio transactions entailed a net addition of 166 mmBOE and comprised: (i) the purchase of interests in the Concessions Agreements of Lower Zakum (Eni's interest 5%) and Umm Shaif and Nasr (Eni's interest 10%) currently producing offshore Abu Dhabi; (ii) the disposal of a 10% interest in the Zohr gas field and other minor assets in Croatia, Trinidad and Tobago and Indonesia, while the business combination between Eni Norge and Point Resources, leading to the creation of Vår Energi, an equity-accounted joint venture (Eni's interest 69.6%) did not produced any meaningful effects as the reserves divested in connection with the loss of control over the former subsidiary Eni Norge were offset by the acquisition of Eni's interest in the reserves of the equity-accounted combined entity. These net increases were partly offset by production of the year and the de-booking of 106 mmBOE of proved undeveloped reserves at an oil project in Venezuela driven by a deteriorated operational environment in accordance with the applicable SEC rules (for further information see Item 3 – Risk Factor).

All sources additions to proved reserves booked in 2018 were 839 mmBOE; of which 576 mmBOE came from Eni's subsidiaries, while 263 mmBOE from Eni's equity-accounted entities, which included a negative revision due to the de-booking reserves in Venezuela as described above.

Price effects were negative, leading to a downward revision of 38 mmBOE, due to an increased Brent price used in the reserves estimation process up to 71.4 $/BBL in 2018 compared to 54.4 $/BBL in 2017. Further information about how to determine year-end amounts of proved reserves and the relevant net present value is provided in "Item 3 – Risk factors – Risks associated with the exploration and production of oil and natural gas".

The methods (or technologies) used in the Eni's proved reserves assessment in 2018 depend on stage of development, quality and completeness of data, and production history availability. The methods include volumetric estimates, analogies, reservoir modelling, decline curve analysis or a combination of such methods. The data considered for these analyses are obtained from a combination of reliable technologies that produce consistent and repeatable results including well or field measurements (i.e. logs, core samples, pressure information, fluid samples, production test data and performance data) and indirect measurements (i.e. seismic data). However for each reservoir assessment the most suitable combination of technologies and methods is applied providing a high degree of confidence in establishing reliable reserves estimates.

The all sources reserves replacement ratio reported by Eni's subsidiaries and equity-accounted entities was 124% in 2018 (25% in 2017 and 193% in 2016). The organic reserves replacement ratio was 100% (103% in 2017 and 193% in 2016) which excluded sales and purchases of minerals-in-place. The de-booking of reserves at an oil project in Venezuela cut 15 percentage points from the reserves replacement ratio.

The all sources reserves replacement ratio was calculated by dividing additions to proved reserves including sales and purchases of mineral-in-place by total production, each as derived from the tables of changes in proved reserves prepared in accordance with FASB Extractive Activities – Oil & Gas (Topic 932) (see the supplemental oil and gas information in "Item 18 – Consolidated Financial Statements"). The reserves replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by booked reserves total additions. Management considers the reserve replacement ratio to be an important indicator of the Company's ability to sustain its growth prospects.

However, this ratio measures past performances and is not an indicator of future production because the ultimate recovery of reserves is subject to a number of risks and uncertainties. These include the risks associated with the successful completion of large-scale projects, including addressing ongoing regulatory issues and completion of infrastructures, reservoir performance, application of new technologies to improve the recovery factor as well as changes in oil&gas prices, political risks and geological and environmental risks. See "Item 3 – Risks associated with the exploration and production of oil and natural gas – Uncertainties in estimates of oil and natural gas reserves".

The average reserves life index of Eni's proved reserves was 10.6 years as of December 31, 2018, which included reserves of both subsidiaries and equity-accounted entities.

Eni's subsidiaries

Eni's subsidiaries added 576 mmBOE of proved oil and gas reserves in 2018 net of sales and purchase of minerals-in-place. This comprised 239 mmBBL of liquids and 1,838 BCF of natural gas. The breakdown of additions to proved reserves is the following: (i) extensions and discoveries were up by 169 mmBOE mainly due to the final investment decisions made for the operated projects of Area 1 in offshore Mexico, Merakes in Indonesia and Argo and Cassiopea offshore Italy; (ii) revisions of previous estimates were up by 590 mmBOE and mainly derived from progress in development activities at the Zohr and Nidoco NW projects in Egypt and at the Kashagan project in Kazakhstan; (iii) improved recovery were 13 mmBOE mainly reported in Egypt and Iraq; (iv) purchases of mineral-in-place referred to assets in United Arab Emirates as described above; and (v) sales of minerals-in-place referred to the disposal of a 10% stake in the Zohr gas field offshore in Egypt as well as the divest of certain minor assets in Croatia and Trinidad and Tobago. In addition, sales of minerals-in-place included the business combination between Eni Norge AS and Point Resources AS. The merger agreement provided for the sale of the reserves of the former subsidiary Eni Norge as part of the business combination with Point Resources and the acquisition of Eni's share of the reserves held by the combined company Vår Energi, an equity-accounted entity participated by Eni with a 69.6% interest. Further information is provided in "Oil and gas properties, operations and acreage" in Eni's principal oil and gas activities described in Egypt, Norway and the United Arab Emirates, respectively.

Eni's share of equity-accounted entities

All sources additions in Eni's share of equity-accounted entities' proved oil and gas were 263 mmBOE in 2018 and derived mainly from: (i) revisions of previous estimates were down by 99 mmBOE due to the de-booking of 106 mmBOE in Venezuela in accordance with the applicable SEC rules; and (ii) the purchase of minerals-in-place due to the business combination in Norway described above.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2018 totaled 2,309 mmBOE. At year-end, proved undeveloped reserves of liquids amounted to 1,127 mmBBL, mainly concentrated in Africa and Asia. Proved undeveloped reserves of natural gas amounted to 6,458 BCF, mainly located in Africa. Proved undeveloped reserves of consolidated subsidiaries amounted to 975 mmBBL of liquids and 6,121 BCF of natural gas. The table below provide a summary of changes in total proved undeveloped reserves for 2018.

Subsidiaries and equity-accounted entities (mmBOE)	**2018**
Proved undeveloped reserves as of December 31, 2017	**2,629**
Reclassification to proved developed reserves	(777)
Extensions and discoveries	166
Revisions of previous estimates	278
Improved recovery	6
Purchases of minerals-in-place	280
Sales of minerals-in-place	(273)
Proved undeveloped reserves as of December 31, 2018	**2,309**

In 2018, total proved undeveloped reserves decreased by 320 mmBOE mainly due to progress made in maturing PUD to proved developed (777 mmBOE). Additions to PUD for the year included: (i) extensions and discoveries (up by 166 mmBOE) due to the final investment decision made for the Area 1 project offshore Mexico and the Merakes project in Indonesia; (ii) revisions of previous estimates (up by 278 mmBOE) mainly reported in Egypt due to the development activity of the Zohr project and included the de-booking of reserves in Venezuela as described above; (iii) improved recovery (up by 6 mmBOE) in particular in Iraq. The net effect of portfolio transactions was negligible.

During 2018, Eni matured 777 mmBOE of proved undeveloped reserves to proved developed reserves due to progress in development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Zohr (Egypt), Kashagan (Kazakhstan); Bahr Essalam and Wafa (Libya) and Sankofa (Ghana).

In 2018, capital expenditures amounted to approximately €6.2 billion and was made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The Company estimates that approximately 0.6 BBOE of proved undeveloped reserves have remained undeveloped for five years or more at the balance sheet date and decreased 0.4 BBOE from 2017 due to the progress in development activities made in Kazakhstan, Iraq and Libya as well as the de-booking of reserves in Venezuela. The proved undeveloped reserves that have remained undeveloped for five years or more at the balance sheet date mainly related to: (i) the Kashagan project in Kazakhstan (0.1 BBOE) due to the complexity of development activities which took more time than initially planned. The project PUD reserves are part of the initial development phase, the production plants and infrastructures of which have been fully commissioned and will support development of the residual project PUD (for further information see “Item 4 – Oil and gas properties, operations and acreage – Kashagan”); (ii) the Zubair field in Iraq (0.1 BBOE), where development of PUDs has been conditioned by the drilling of additional production and injection wells to be linked to the production facilities, which were already completed to achieve the full field production plateau of 700 KBBL/d; (iii) certain Libyan gas fields (0.4 BBOE) where development completion and production start-ups are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force. In order to secure fulfillment of the contractual delivery quantities, Eni will implement phased production start-up from the relevant fields, which are expected to be put in production over the next several years. (See also our discussion under the “Risk factors” section about risks associated with oil and gas development projects).

Eni remains strongly committed to put these projects into production in the coming years. The length of the development period depends on a range of external factors, such as for example the type of development, the location and physical operating environment of the field or the absence of infrastructure, considering that the majority of our projects are infrastructure-driven, and not a function of internal factors, such as an insufficient devotion of resources by Eni or a diminished commitment on the part of Eni to complete the project.

Delivery commitments

Eni, through consolidated subsidiaries and equity-accounted entities, sells crude oil and natural gas from its producing operations under a variety of contractual obligations. Some of these contracts, mostly relating to natural gas, specify the delivery of fixed and determinable quantities.

Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 536 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Ghana, Indonesia, Libya, Nigeria, Norway and Venezuela.

The sales contracts contain a mix of fixed and variable pricing formulas that are generally indexed to the market price for crude oil, natural gas or other petroleum products. Management believes it can satisfy these contracts from quantities available from production of the Company's proved developed reserves and supplies from third parties based on existing contracts. Production is expected to account for approximately 88% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2018.

Oil and gas production, production prices and production costs

The matters regarding future production, additions to reserves and related production costs and estimated reserves discussed below and elsewhere herein are forward-looking statements that involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties relating to future production and additions to reserves include political developments affecting the award of exploration or production interests or world supply and prices for oil and natural gas, or changes in the underlying economics of certain of Eni's important hydrocarbons projects. Such risks and uncertainties relating to future production costs include delays or unexpected costs incurred in Eni's production operations.

In 2018, oil and natural gas production available for sale averaged 1,732 KBOE/d (1,719 KBOE/d in 2017) and increased by approximately 1% from 2017, mainly due to the ramp-ups at fields started up in 2017 mainly in Egypt, Indonesia, Angola, Congo and Ghana, new project start-ups in 2018, higher production at the Kashagan field, Goliat field in Norway and Val d'Agri in Italy, as well as the acquisition of the two Concession Agreements Lower Zakum (5%) and Umm Shaif/Nasr (10%) producing offshore in the United Arab Emirates. These positives were partly offset by negative price effects at PSAs contracts, lower-than-expected produced gas volumes due to the impact of exogenous factors in certain countries, the decline of mature fields as well as certain one-off events (termination of the Intisar contract in Libya and unplanned shutdowns). New field start-ups and ramp-ups of production added an estimated more than 300 KBOE/d of new production.

Liquids production (884 KBBL/d) increased by 32 KBBL/d, or approximately 4% from the full year of 2017. Ramp-ups of the year and the acquisition of two producing concessions in the United Arab Emirates were partly offset by price effect and mature fields decline.

Natural gas production (4,630 mmCF/d) decreased by 104 mmCF/d, or approximately 2% compared to the full year of 2017. Production ramp-ups and start-ups were offset by factors out of management control, particularly a lower-than-expected gas demand in certain geographies.

Sales volumes of oil and gas production sold were 625 mmBOE. The 7 mmBOE difference over production on available-for-sale basis (632 mmBOE in 2018) reflected mainly changes in inventory and other factors. Approximately 70% of liquids production sold (320 mmBBL) was destined to Eni's mid-downstream sectors. About 20% of natural gas production sold (1,665 BCF) was destined to Eni's Gas & Power segment.

The tables below provide Eni subsidiaries and its equity-accounted entities' production (annual volumes and daily averages), by final product marketed of liquids and natural gas by country and geographical area of each of the last three fiscal years.

Average daily production available for sale[(a)]

	2018			2017			2016		
	Liquids (KBBL/d)	Natural gas (mmCF/d)	Hydrocarbons (KBOE/d)	Liquids (KBBL/d)	Natural gas (mmCF/d)	Hydrocarbons (KBOE/d)	Liquids (KBBL/d)	Natural gas (mmCF/d)	Hydrocarbons (KBOE/d)
Eni consolidated subsidiaries									
Italy	**60**	**386**	**130**	**53**	**402**	**127**	**47**	**436**	**127**
Rest of Europe	**113**	**410**	**188**	**102**	**443**	**183**	**109**	**468**	**195**
Croatia		10	2		16	3		24	4
Norway	89	225	131	81	250	126	86	244	131
United Kingdom	24	175	55	21	177	54	23	200	60
North Africa	**154**	**1,188**	**372**	**158**	**1,632**	**457**	**165**	**1,486**	**438**
Algeria	65	35	72	68	35	75	77	44	85
Libya	86	1,141	295	87	1,585	377	84	1,429	346
Tunisia	3	12	5	3	12	5	4	13	7
Egypt	**77**	**1,147**	**287**	**72**	**784**	**216**	**76**	**514**	**170**
Sub-Saharan Africa	**244**	**346**	**308**	**247**	**328**	**305**	**247**	**353**	**312**
Angola	111		111	119		119	108		108
Congo	65	104	84	63	68	74	71	112	92
Ghana	15	9	17	8		8			
Nigeria	53	233	96	57	260	104	68	241	112
Kazakhstan	**91**	**228**	**133**	**83**	**231**	**126**	**65**	**234**	**107**
Rest of Asia	**77**	**412**	**152**	**53**	**282**	**105**	**78**	**199**	**115**
China	1		1	2		2	2		2
Indonesia	3	315	60	3	161	33	3	39	10
Iraq	28		28	40		40	64		64
Pakistan		97	18		121	22		160	30
Turkmenistan	6		6	8		8	9		9
United Arab Emirates	39		39						
Americas	**52**	**108**	**72**	**63**	**181**	**96**	**69**	**243**	**113**
Ecuador	12		12	12		12	10		10
Trinidad & Tobago		36	6		55	10		70	12
United States	40	72	54	51	126	74	59	173	91
Australia and Oceania	**2**	**110**	**22**	**2**	**101**	**21**	**3**	**110**	**23**
Australia	2	110	22	2	101	21	3	110	23
	870	**4,335**	**1,664**	**833**	**4,384**	**1,636**	**859**	**4,043**	**1,600**
Eni's share of equity-accounted entities									
Angola	3	75	17	3	72	17	1	16	4
Indonesia		2	1	1	9	2	1	15	4
Tunisia	3	2	3	3	2	3	3	3	3
Venezuela	8	216	47	12	267	61	14	252	60
	14	**295**	**68**	**19**	**350**	**83**	**19**	**286**	**71**
Total	**884**	**4,630**	**1,732**	**852**	**4,734**	**1,719**	**878**	**4,329**	**1,671**

(a) It excludes production volumes of hydrocarbons consumed in operations. Said volumes were 119, 97 and 88 KBOE/d in 2018, 2017 and 2016, respectively.

Annual production available for sale [(a)]

	2018			2017			2016		
	Liquids (mmBBL)	Natural gas (BCF)	Hydrocarbons (mmBOE)	Liquids (mmBBL)	Natural gas (BCF)	Hydrocarbons (mmBOE)	Liquids (mmBBL)	Natural gas (BCF)	Hydrocarbons (mmBOE)
Eni consolidated subsidiaries									
Italy	**22**	**141**	**48**	**19**	**147**	**46**	**17**	**159**	**47**
Rest of Europe	**41**	**150**	**68**	**37**	**162**	**67**	**40**	**171**	**71**
Croatia		4	1		6	1		9	1
Norway	33	82	47	29	91	46	31	89	48
United Kingdom	8	64	20	8	65	20	9	73	22
North Africa	**56**	**434**	**136**	**58**	**596**	**167**	**60**	**544**	**160**
Algeria	24	13	26	25	13	27	28	16	31
Libya	31	417	108	32	579	138	31	523	127
Tunisia	1	4	2	1	4	2	1	5	2
Egypt	**28**	**419**	**105**	**26**	**286**	**79**	**28**	**188**	**62**
Sub-Saharan Africa	**89**	**126**	**112**	**90**	**119**	**111**	**91**	**129**	**114**
Angola	41		41	43		43	40		40
Congo	24	38	30	23	24	27	26	41	33
Ghana	5	3	6	3		3			
Nigeria	19	85	35	21	95	38	25	88	41
Kazakhstan	**34**	**83**	**49**	**30**	**84**	**46**	**24**	**86**	**39**
Rest of Asia	**28**	**150**	**55**	**20**	**103**	**38**	**28**	**73**	**42**
China	1		1	1		1	1		1
Indonesia	1	115	22	1	59	11	1	14	4
Iraq	10		10	15		15	23		23
Pakistan		35	6		44	8		59	11
Turkmenistan	2		2	3		3	3		3
United Arab Emirates	14		14						
Americas	**19**	**40**	**26**	**23**	**66**	**35**	**25**	**89**	**42**
Ecuador	4		4	4		4	4		4
Trinidad & Tobago		13	2		20	4		25	5
United States	15	27	20	19	46	27	21	64	33
Australia and Oceania	**1**	**40**	**8**	**1**	**37**	**8**	**1**	**40**	**8**
Australia	1	40	8	1	37	8	1	40	8
	318	**1,583**	**607**	**304**	**1,600**	**597**	**314**	**1,479**	**585**
Eni's share of equity-accounted entities									
Angola	1	27	6	1	27	6		6	2
Indonesia				1	3	1	1	6	2
Tunisia	1	1	1	1	1	1	1	1	1
Venezuela	3	79	18	4	97	22	5	92	22
	5	**107**	**25**	**7**	**128**	**30**	**7**	**105**	**27**
Total	**323**	**1,690**	**632**	**311**	**1,728**	**627**	**321**	**1,584**	**612**

(a) It excludes production volumes of hydrocarbons consumed in operations. Said volumes were 43.5, 35.2 and 32.1 mmBOE in 2018, 2017 and 2016, respectively.

Volumes of oil and natural gas purchased under long-term supply contracts with foreign governments or similar entities in properties where Eni acts as producer totaled 54 KBOE/d, 55 KBOE/d and 56 KBOE/d in 2018, 2017 and 2016, respectively.

The tables below provide Eni subsidiaries and its equity-accounted entities' average sales prices per unit of liquids and natural gas by geographical area for each of the last three fiscal years. In addition, Eni subsidiaries and its equity-accounted entities' average production cost per unit of production are provided. With effect from January 1, 2018, with a view to conforming to customary industry practice and in accordance with the applicable SEC rules, Eni has changed the method for calculating the average production cost per barrel-of-oil equivalent. Average production costs no longer include the following items which have previously been included: (i) Royalties and other production taxes; and (ii) Transportation costs relating to the export of the saleable volumes of oil and gas produced, other than the costs incurred to deliver hydrocarbons to a main pipeline, a common carrier, a refinery or a maritime terminal, when unusual physical or operational circumstances exist. A full reconciliation between recomputed average production costs and originally-published amounts by geographic area in 2016 e 2017 is disclosed in the following tables.

Average sales prices and production costs per unit of production

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2016										
Consolidated subsidiaries										
Oil and condensates, per BBL	33.19	39.97	42.37	33.05	41.92	39.61	36.89	34.86	37.96	**39.33**
Natural gas, per KCF	4.93	4.49	3.10	3.82	1.41	0.34	3.50	1.94	3.60	**3.20**
Average production cost, per BOE	7.31	6.77	2.79	6.11	8.99	4.98	5.61	7.00	6.44	**5.90**
Equity-accounted entities										
Oil and condensates, per BBL			17.93				34.95	32.39		**30.85**
Natural gas, per KCF			1.85				5.92	4.17		**4.25**
Average production cost, per BOE			5.78				8.19	2.58		**2.89**
2017										
Consolidated subsidiaries										
Oil and condensates, per BBL	46.51	47.81	52.68	46.06	53.66	50.62	48.94	44.24	49.36	**50.33**
Natural gas, per KCF	6.45	5.81	2.96	4.19	1.87	0.58	3.75	2.35	4.05	**3.62**
Average production cost, per BOE	8.12	8.85	3.08	4.35	9.64	6.68	5.96	8.36	7.11	**6.33**
Equity-accounted entities										
Oil and condensates, per BBL			17.95		38.34		44.43	41.49		**38.65**
Natural gas, per KCF			2.63		7.34		6.06	4.19		**4.64**
Average production cost, per BOE			5.94		3.45		11.64	1.99		**2.71**
2018										
Consolidated subsidiaries										
Oil and condensates, per BBL	61.58	64.51	65.95	62.97	68.76	66.78	68.35	57.22	68.72	**65.79**
Natural gas, per KCF	8.37	7.99	4.97	4.85	2.38	0.77	6.11	2.38	4.80	**5.17**
Average production cost, per BOE	9.97	8.39	3.16	3.87	10.25	6.53	4.68	10.56	7.09	**6.50**
Equity-accounted entities										
Oil and condensates, per BBL			17.92		39.48		49.86	54.86		**45.19**
Natural gas, per KCF			3.58		9.50		9.32	4.28		**5.59**
Average production cost, per BOE			6.84		6.53		11.03	2.47		**3.76**

Full reconciliation between recomputed average production costs and originally-published data

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2017										
Consolidated subsidiaries										
Average production cost, per BOE (as published)	11.43	11.62	4.76	4.51	13.34	9.78	6.39	10.10	7.77	**8.45**
less: – Royalties	(3.19)		(1.35)		(3.35)		(0.31)		(0.66)	**(1.28)**
– Transportation costs	(0.12)	(2.77)	(0.33)	(0.16)	(0.35)	(3.10)	(0.12)	(1.74)		**(0.84)**
Average production cost, per BOE (as recomputed)	8.12	8.85	3.08	4.35	9.64	6.68	5.96	8.36	7.11	**6.33**
Equity-accounted entities										
Average production cost, per BOE (as published)			10.30		8.05		11.64	9.52		**9.31**
less: – Royalties			(2.18)		(1.45)			(7.48)		**(5.82)**
– Transportation costs			(2.18)		(3.15)			(0.05)		**(0.78)**
Average production cost, per BOE (as recomputed)			5.94		3.45		11.64	1.99		**2.71**

($)	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2016										
Consolidated subsidiaries										
Average production cost, per BOE (as published)	9.69	9.31	4.33	6.34	12.09	7.58	6.14	8.70	7.08	**7.79**
less: – Royalties	(2.28)		(1.21)		(2.73)		(0.45)		(0.64)	**(1.09)**
– Transportation costs	(0.10)	(2.54)	(0.33)	(0.23)	(0.37)	(2.60)	(0.08)	(1.70)		**(0.80)**
Average production cost, per BOE (as recomputed)	7.31	6.77	2.79	6.11	8.99	4.98	5.61	7.00	6.44	**5.90**
Equity-accounted entities										
Average production cost, per BOE (as published)			9.74				8.19	8.81		**8.34**
less: – Royalties			(2.38)					(6.08)		**(5.24)**
– Transportation costs			(1.58)					(0.15)		**(0.21)**
Average production cost, per BOE (as recomputed)			5.78				8.19	2.58		**2.89**

Development well activity

In 2018, a total of 209 development wells were drilled (80.2 of which represented Eni's share) as compared to 178 development wells drilled in 2017 (90.7 of which represented Eni's share) and 296 development wells drilled in 2016 (118.7 of which represented Eni's share).

The drilling of 38 development wells (10.6 of which represented Eni's share) is currently underway.

The table below summarizes the number of the Company's net interest in productive and dry development wells completed in each of the past three years and the status of the Company's development wells in the process of being drilled as of December 31, 2018. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Net wells completed						**Wells in progress at 31 Dec.**	
	2018		**2017**		**2016**		**2018**	
(units)	**Productive**	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**	**Gross**	**Net**
Italy	3.0		2.6		4.0			
Rest of Europe	2.8	0.3	2.7	0.2	5.6		16.0	1.3
North Africa	9.6	0.5	5.1		6.2	0.7	3.0	1.4
Egypt	30.7		49.7	2.3	32.4	0.5	5.0	2.1
Sub-Saharan Africa	7.3	0.1	8.6		21.2	0.2	6.0	2.5
Kazakhstan	0.9		1.2		4.6		1.0	0.3
Rest of Asia	21.9		15.0	0.2	31.6	0.5	7.0	3.0
Americas	2.3		3.1		9.9	1.3		
Australia and Oceania	0.8							
Total including equity-accounted entities	**79.3**	**0.9**	**88.0**	**2.7**	**115.5**	**3.2**	**38.0**	**10.6**

Exploration well activity

In 2018, a total of 24 new exploratory wells were drilled (15.6 of which represented Eni's share), as compared to 25 exploratory wells drilled in 2017 (15.9 of which represented Eni's share) and 16 exploratory wells drilled in 2016 (10.2 of which represented Eni's share).

The overall commercial success rate was 62% (66% net to Eni) as compared to 60% (52% net to Eni) and 50% (50% net to Eni) in 2017 and 2016, respectively.

The following table summarizes the Company's net interests in productive and dry exploratory wells completed in each of the last three fiscal years and the number of exploratory wells in the process of being drilled and evaluated as of December 31, 2018. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

	Net wells completed						Wells in progress at Dec. 31[(1)]	
	2018		2017		2016		2018	
(units)	**Productive**	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**	**Gross**	**Net**
Italy	1.8					1.0	1.0	0.5
Rest of Europe		0.5	1.2	1.3	0.1	0.4	12.0	3.5
North Africa		0.5	0.5		0.5	1.0	8.0	7.0
Egypt	1.7	1.5	2.5	5.4	5.5	0.8	11.0	8.9
Sub-Saharan Africa	0.4		2.9	0.3	0.1	1.1	31.0	15.1
Kazakhstan							6.0	1.0
Rest of Asia	2.2	2.6				0.9	8.0	2.5
Americas	4.0		0.5			1.0	2.0	1.5
Australia and Oceania							1.0	0.3
Total including equity-accounted entities	**10.1**	**5.1**	**7.6**	**7.0**	**6.2**	**6.2**	**80.0**	**40.3**

(1) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

In 2018, Eni performed its operations in 43 countries located in five continents. As of December 31, 2018, Eni's mineral right portfolio consisted of 902 exclusive or shared rights of exploration and development activities for a total acreage of 406,505 square kilometers net to Eni (414,918 square kilometers net to Eni as of December 31, 2017). Developed acreage was 28,386 square kilometers and undeveloped acreage was 378,119 square kilometers net to Eni.

In 2018, main changes derived from: (i) new leases mainly in the United Arab Emirates, Indonesia, Lebanon, Morocco, Mexico, Norway and the United States for a total acreage of approximately 31,000 square kilometers; (ii) the total relinquishment of licenses mainly in Australia, China, Egypt, Indonesia, Morocco, Pakistan, Russia, the United Kingdom and Ukraine covering an acreage of approximately 35,000 square kilometers; (iii) interest increase mainly in Angola and Ireland for a total acreage of approximately 2,000 square kilometers; (iv) partial relinquishment in Cyprus, Gabon and Indonesia or interest reduction mainly in Egypt, Norway and Pakistan for approximately 6,400 square kilometers.

In October 2018, Eni submitted to the relevant Authorities of Portugal the documentation required for voluntary release of exploration concessions, with effective date as of January 31, 2019.

The table below provides certain information about the Company's oil&gas properties. It provides the total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interest as of December 31, 2018. A gross acreage is one in which Eni owns a working interest.

	December 31, 2017	December 31, 2018						
	Total net acreage [(a)]	Number of interests	Gross developed acreage [(a) (b)]	Gross undeveloped acreage [(a)]	Total gross acreage [(a)]	Net developed acreage [(a) (b)]	Net undeveloped acreage [(a)]	Total net acreage [(a)]
EUROPE	**51,206**	**317**	**13,757**	**58,376**	**72,133**	**9,409**	**36,923**	**46,332**
Italy	**16,380**	**140**	**9,962**	**8,871**	**18,833**	**8,303**	**6,684**	**14,987**
Rest of Europe	**34,826**	**177**	**3,795**	**49,505**	**53,300**	**1,106**	**30,239**	**31,345**
Cyprus	17,967	6		22,790	22,790		17,111	17,111
Croatia	987							
Greenland	1,909	2		4,890	4,890		1,909	1,909
Montenegro	614	1		1,228	1,228		614	614
Norway	2,117	106	2,886	9,630	12,516	492	2,136	2,628
Portugal	3,182	3		4,547	4,547		3,182	3,182
United Kingdom	5,805	57	909	3,719	4,628	614	3,404	4,018
Other Countries	2,245	2		2,701	2,701		1,883	1,883
AFRICA	**161,981**	**261**	**46,263**	**258,232**	**304,495**	**11,844**	**153,855**	**165,699**
North Africa	**25,797**	**64**	**8,846**	**48,760**	**57,606**	**3,640**	**30,292**	**33,932**
Algeria	1,141	42	3,283	187	3,470	1,124	31	1,155
Libya	13,294	11	1,963	24,673	26,636	958	12,336	13,294
Morocco	9,804	1		23,900	23,900		17,925	17,925
Tunisia	1,558	10	3,600		3,600	1,558		1,558
Egypt	**9,192**	**53**	**5,423**	**10,480**	**15,903**	**2,018**	**3,230**	**5,248**
Sub-Saharan Africa	**126,992**	**144**	**31,994**	**198,992**	**230,986**	**6,186**	**120,333**	**126,519**
Angola	4,367	58	8,200	13,241	21,441	1,064	4,239	5,303
Congo	1,471	25	1,430	1,320	2,750	843	628	1,471
Gabon	5,283	4		4,107	4,107		4,107	4,107
Ghana	579	3	226	1,127	1,353	100	479	579
Ivory Coast	2,905	3		4,010	4,010		2,905	2,905
Kenya	43,948	6		50,677	50,677		43,948	43,948
Liberia	585							
Mozambique	978	6		3,911	3,911		978	978
Nigeria	7,370	34	22,138	8,631	30,769	4,179	3,543	7,722
South Africa	26,202	1		65,505	65,505		26,202	26,202
Other Countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	**184,029**	**61**	**13,024**	**285,289**	**298,313**	**3,368**	**178,046**	**181,414**
Kazakhstan	**1,543**	**7**	**2,391**	**3,890**	**6,281**	**442**	**1,101**	**1,543**
Rest of Asia	**182,486**	**54**	**10,633**	**281,399**	**292,032**	**2,926**	**176,945**	**179,871**
China	7,154	7	77	5,215	5,292	13	5,215	5,228
India	5,244	1		13,110	13,110		5,244	5,244
Indonesia	22,889	13	2,943	27,230	30,173	1,198	22,571	23,769
Iraq	446	1	1,074		1,074	446		446
Lebanon		2		3,653			1,461	
Myanmar	13,558	4		24,080	24,080		13,558	13,558
Oman	77,146	1		90,760	90,760		77,146	77,146
Pakistan	7,401	12	3,390	11,486	14,876	872	4,914	5,786
Russia	20,862	2		53,930	53,930		17,975	17,975
Timor Leste	1,230	1		1,538	1,538		1,230	1,230
Turkmenistan	180	1	200		200	180		180
United Arab Emirates		3	2,949	5,020	7,969	217	1,255	1,472
Vietnam	23,132	5		30,777	30,777		23,132	23,132
Other Countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**6,641**	**252**	**4,419**	**12,543**	**16,962**	**3,056**	**6,247**	**9,303**
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico	1,146	8		4,387	4,387		3,000	3,000
Trinidad & Tobago	66							
United States	1,052	230	1,173	1,949	3,122	574	1,617	2,191
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other Countries	1,326	7		4,664	4,664		1,061	1,061
AUSTRALIA AND OCEANIA	**11,061**	**11**	**1,140**	**4,611**	**5,751**	**709**	**3,048**	**3,757**
Australia	11,061	11	1,140	4,611	5,751	709	3,048	3,757
Total	**414,918**	**902**	**78,603**	**619,051**	**697,654**	**28,386**	**378,119**	**406,505**

(a) Square kilometers.

(b) Developed acreage refers to those leases in which at least a portion of the area is in production or encompasses proved developed reserves.

The table below sets forth, as of December 31, 2018 and by main producing countries in each geographic area, Eni's producing assets, the year in which Eni's activities started, the Eni's participating interest in each assets and whether Eni is operator of the asset.

ITALY	**(1926)**	**Operated**	**Adriatic and Ionian Sea**: Barbara (100%), Cervia/Arianna (100%), Annamaria (100%), Clara NW (51%), Luna (100%), Angela (100%), Hera Lacinia (100%) and Bonaccia (100%) **Basilicata Region**: Val d'Agri (60.77%) **Sicily Region**: Gela (100%), Tresauro (45%), Giaurone (100%), Fiumetto (100%), Prezioso (100%) and Bronte (100%)
REST OF EUROPE			
Norway [(a)]	**(1965)**	**Operated**	Goliat (45.24%), Marulk (13.92%), Balder & Ringhorne (69.6%) and Ringhorne East (53.85%)
		Non-operated	Åsgard (10.31%), Kristin (5.74%), Heidrun (3.60%), Mikkel (10.37%), Tyrihans (4.32%), Morvin (20.88%), Great Ekofisk Area (8.62%), Boyla (13.92%), Brage (8.53%) and Snorre (0.7%)
United Kingdom	**(1964)**	**Operated**	Liverpool Bay (100%) and Hewett Area (89.3%)
		Non-operated	Elgin/Franklin (21.87%), Glenelg (8%), J Block (33%), Jasmine (33%) and Jade (7%)
NORTH AFRICA			
Algeria [(b)]	**(1981)**	**Operated**	Blocks 403a/d (from 65% to 100%), Block ROM North (35%), Blocks 401a/402a (55%), Block 403 (50%) and Block 405b (75%)
		Non-operated	Block 404 (12.25%) and Block 208 (12.25%)
Libya [(b)]	**(1959)**	**Non-operated**	**Onshore contract areas:** Area A (former concession 82 – 50%), Area B (former concession 100/Bu-Attifel and Block NC 125 – 50%), Area E (El Feel – 33.3%), Area F (Block 118 – 50%) and Area D (Block NC 169 – 50%) **Offshore contract areas:** Area C (Bouri – 50%) and Area D (Block NC 41 – 50%)
Tunisia	**(1961)**	**Operated**	Maamoura (49%), Baraka (49%), Adam (25%), Oued Zar (50%), Djebel Grouz (50%), MLD (50%) and El Borma (50%)
EGYPT [(b)(c)]	**(1954)**	**Operated**	Shorouk (Zohr – 50%), Nile Delta (Abu Madi West/ Nidoco – 75%), Sinai (Belayim Land, Belayim Marine and Abu Rudeis – 100%), Melehia (76%), North Port Said (Port Fouad – 100%), Temsah (Tuna, Temsah e Denise – 50%), Baltim (50%), Ras Qattara (El Faras e Zarif – 75%), West Abu Gharadig (Raml – 45%), Ashrafi (50%) and North Razzak (100%)
		Non-operated	Ras el Barr (Ha'py and Seth – 50%) and South Ghara (25%)
SUB-SAHARAN AFRICA			
Angola	**(1980)**	**Operated**	Blocco 15/06 (36.84%)
		Non-operated	Block 0 (9.8%), Development Areas in the Block 3 and 3/05-A (12%), Development Areas in the Block 14 (20%), Development Area Lianzi in the Blocco 14K/A IMI (10%) and the Development Areas in the Block 15 (20%)
Congo	**(1968)**	**Operated**	Nené Marine (65%), Litchendjili (65%), Zatchi (55,25%), Loango (42,5%), Ikalou (100%), Djambala (50%), Foukanda (58%), Mwafi (58%), Kitina (52%), Awa Paloukou (90%), M'Boundi (82%), Kouakouala (74.25%), Zingali (100%) and Loufika (100%)
		Non-operated	Pointe-Noire Grand Fond (35%) and Likouala (35%)
Ghana	**(2009)**	**Operated**	Offshore Cape Three Points (44.44%)
Nigeria	**(1962)**	**Operated**	OMLs 60, 61, 62 and 63 (20%), OML 125 (100%) and OPL 245 (50%)
		Non-operated [(d)]	OML 118 (12.5%) and service contract OML 116
KAZAKHSTAN [(b)]	**(1992)**	**Operated** [(e)]	Karachaganak (29.25%)
		Non-operated	Kashagan (16.81%)
REST OF ASIA			
Indonesia	**(2001)**	**Operated**	Jangkrik (55%)
Iraq	**(2009)**	**Operated** [(f)]	Zubair (41.6%)
Pakistan	**(2000)**	**Operated**	Bhit/Bhadra (40%) and Kadanwari (18.42%)
		Non-operated	Latif (33.3%), Zamzama (17.75%) and Sawan (23.7%)
Turkmenistan	**(2008)**	**Operated**	Burun (90%)
United Arab Emirates	**(2018)**	**Non-operated**	Lower Zakum (5%) and Umm Shaif and Nasr (10%)
AMERICAS			
United States	**(1968)**	**Operated**	**Gulf of Mexico:** Allegheny (100%), Appaloosa (100%), Pegasus (85%), Longhorn (75%), Devils Towers (75%) and Triton (75%) **Alaska:** Nikaitchuq (100%)
		Non-operated	**Gulf of Mexico:** Europa (32%), Medusa (25%), Lucius (8,5%), K2 (13.4%), Frontrunner (37.5%) and Heidelberg (12.5%) **Alaska:** Oooguruk (30%) **Texas:** Alliance area (27.5%)
Venezuela	**(1998)**	**Non-operated**	Perla (50%), Corocoro (26%) and Junin 5 (40%)

(a) Assets held by the Vår Energi equity-accounted entities (Eni's interest 69.6%).

(b) In certain extractive initiatives, Eni and the host Country agree to assign the operatorship of a given initiative to an incorporated joint venture, a so-called operating company. The operating company in its capacity as the operator is responsible of managing extractive operations. Those operating companies are not controlled by Eni.

(c) Eni's working interests (and not participating interests) are reported. Those include Eni's share of costs incurred on behalf of the first party accordingly to the terms of PSAs inforce in the Country.

(d) As partners of SPDC JV, Eni holds a 5% interest in 17 onshore blocks and in 1 conventional offshore block and with a 12.86% in 2 conventional offshore blocks.

(e) Eni and Shell are co-operators.

(f) Eni is leading a consortium of partners including international companies and the national oil company Missan Oil.

The table below provides the number of gross and net productive oil and natural gas wells in which the Group companies and its equity-accounted entities had an interest as of December 31, 2018. A gross well is a well in which Eni owns a working interest. The number of gross wells is the total number of wells in which Eni owns a whole or fractional working interest. The number of net wells is the sum of the whole or fractional working interests in a gross well. One or more completions in the same borehole are counted as one well. Productive wells are producing wells and wells capable of production. The total number of oil and natural gas productive wells is 8,170 (2,836.6 of which represent Eni's share).

Productive oil and gas wells at Dec. 31, 2018[(a)]

(units)	Oil Wells		Natural gas Wells	
	Gross	Net	Gross	Net
Italy	202.0	157.0	479.0	415.9
Rest of Europe	477.0	86.5	135.0	65.3
North Africa	592.0	242.8	116.0	63.2
Egypt	1,194.0	508.3	147.0	48.3
Sub-Saharan Africa	2,747.0	550.4	181.0	23.0
Kazakhstan	200.0	55.1		
Rest of Asia	955.0	336.7	167.0	62.0
Americas	270.0	132.1	284.0	81.7
Australia and Oceania	3.0	1.2	21.0	7.1
Total including equity-accounted entities	**6,640.0**	**2,070.1**	**1,530.0**	**766.5**

(a) Multiple completion wells included above: approximateley 1,445 (450.8 net to Eni).

Eni's exploration and production activities are conducted in many countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and condition of the leases, licenses and contracts under which these oil&gas interests are held vary from country to country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These contractual arrangements usually take the form of concession agreements or production sharing agreements:

- Concession contracts currently applied mainly in Western countries regulating relationships between States and oil companies with regards to hydrocarbon exploration and production activity. Contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. The company holding the mining concession has an exclusive right on exploration, development and production activities, sustaining all the operational risks and costs related to the exploration and development activities, and it is entitled to the productions realized. As a compensation for mineral concessions, pays royalties on production (which may be in cash or in-kind) and taxes on oil revenues to the state in accordance with local tax legislation. Both exploration and production licenses are granted generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases): the term of Eni's licenses and the extent to which these licenses may be renewed vary by area. Proved reserves to which Eni is entitled are determined by applying Eni's share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right.

  In Particular, Eni's exploration and production activities are regulated by concession contracts or a similar scheme mainly in Italy, Ghana, Mozambique, Tunisia, the United Arab Emirates, the United Kingdom, the United States, certain assets in Nigeria, Angola and Australia as well as onshore permits in Pakistan. In Norway, Eni's activities are regulated by Production Licenses (PL). According to a PL, the holder is entitled to perform seismic surveys and drilling and production activities for a given number of years with possible extensions.

- Eni operates under Production Sharing Agreement (PSA) in several of the foreign jurisdictions mainly in African, Middle Eastern, Far Eastern countries. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract, the national oil company assigns to the international contractor the task of performing exploration and production with the contractor's equipment (technologies) and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "Cost Oil" is used to recover costs borne by the contractor and "Profit Oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country. Pursuant to these contracts, Eni is entitled to a portion of a field's reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The Company's share of production volumes and reserves representing the Profit Oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. As a consequence, the Company has to recognize at the same time an increase in the taxable profit, through the increase of the revenues, and a tax expense. Proved reserves to which Eni is entitled under PSAs are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (Cost Oil) and recognize the Profit Oil set contractually (Profit Oil).
  A similar scheme applies to some Service contracts.
  Eni's exploration and production activities are regulated by PSA or scheme similar in Algeria, Angola, China, Congo, Egypt, Indonesia, Libya, Mexico, certain assets in Nigeria, Kazakhstan and offshore assets in Pakistan. In addition, Eni's activities are regulated by service contract in one block in Nigeria and in Ecuador. In Australia, the cooperation zone between Timor Leste and Australia (Joint Petroleum Development Area – JPDA) are regulated by PSAs. Development and production activities in Iraq are regulated by a technical service contract. This contractual scheme establishes an oil entitlement mechanism and an associated risk profile similar to those applicable to PSA.

Eni's principal oil and gas properties are described below. In the discussion that follows, references to hydrocarbon production are intended to represent hydrocarbon production available for sale.

Italy

Eni's activities in Italy are deployed in the Adriatic and Ionian Seas, the Central Southern Apennines, mainland and offshore Sicily and the Po Valley. Eni operates 48 onshore and 62 offshore concessions as well as 11 onshore and 9 offshore exploration licenses. In 2018, Italy accounted for 7% of Eni's total worldwide production of oil and natural gas.

Eni's domestic production in 2018 was accounted for 40% in the Adriatic and Ionian Seas, 46% in the Central Southern Apennines and 9% in Sicily.

Development activities in 2018 mainly concerned: (i) maintenance and production optimization, mainly at the offshore fields; and (ii) the progress in development activities at the Argo and Cassiopea operated project (Eni's interest 60%).

In Italy, a new law has been enacted effective February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan indented to identify areas that are suitable for carrying out oil and gas activities. See "Risk Factors – *Oil and gas activity may be subject to increasingly high levels of regulations throughout the world, which may impact our extraction activities and the recoverability of reserves*". Management is not currently in the position to make a reliable and fair estimation of future impacts of the new law provisions on the recoverability of the volumes of proved reserves booked in Italy and the associated future cash flows. However, based on the review of all facts and circumstances and on the current knowledge of the matter, management does not expects any material impacts on the Group future results of operations and cash flow.

Rest of Europe

Eni's operations in the Rest of Europe are mainly conducted in Norway and the United Kingdom. In 2018, the Rest of Europe accounted for 11% of Eni's total worldwide production of oil and natural gas.

Croatia. In 2018, Eni divested exploration and production activities in the Country.

Norway. In December 2018, it was finalized the business combination between Point Resources AS and Eni Norge AS, fully-owned by HitecVision and Eni respectively, with the creation of Vår Energi AS, an equity-accounted joint venture. The exchange rate of shares was established so that Eni and the Point Reources shareholders would retain participation interests of 69.6% and 30.4% respectively, in the combined entity. The governance of the new entity is designed to establish joint control of the two shareholders over the combined entity. Therefore, effective at the closing, Eni derecognized the assets and liabilities of Eni Norge and recognized the fair value of the interest retained in the merged company that will be equity-accounted going forward.

The transaction intends to strengthen Eni's position in the Country by integrating the asset portfolios of the merged companies and extracting synergies by combining different know-how, skills and resources. Eni gained access to the portfolio of Point Resources, which included producing assets such as the Balder & Ringhorne, Ringhorne East, Boyla, Brage and Snorre fields and a number of development options. The portfolio of the combined company currently comprises seventeen producing oil and gas fields with a wide geographical reach, from the Barents Sea to the North Sea.

Eni retains a first offer right in case the Norwegian private equity funds, managed by HitecVision, decide to divest their interest in the venture.

In 2019, Vår Energi was awarded 13 exploration licenses: (i) the operatorship in two licenses in the North Sea and two licenses in the Barents Sea; and (ii) the interest in five licenses in the North Sea and four licenses in the Norway Sea.

Development activities mainly concerned: (i) the Trestakk project (Eni's interest 5.5%) with start-up expected in 2019; and (ii) the Johan Castberg project in the PL 532 license (Eni's interest 20.88%), which was sanctioned in June 2018. Start-up is expected in 2022

Exploration activity yielded positive results with: (i) delineation well of the Cape Vulture oil and gas discovery in the PL 128/128D license (Eni's interest 8%), nearby to the production facilities of the Norne field (Eni's interest 4.8%); (ii) an oil discovery in the PL 532 license, nearby the Johan Castberg project; (iii) the Goliat West oil well in the PL 229 (Eni's interest 45.24%); and (iv) an oil and gas discovery in the PL 869 which is participated by Vår Energi AS with a 20% interest.

United Kingdom. Development activities mainly concerned: ((i) two infilling wells drilled in Elgin Franklin fields (Eni's interest 21.87%), one in production from September and the second one to be completed in 2019; (ii) two infilling wells in Joanne and Jasmine fields (Eni's interest 33%), both of them in production since May and September, moreover a workover activity started and was completed at the beginning of 2019.

North Africa

Eni's operations in North Africa are conducted in Algeria, Libya, Morocco and Tunisia. In 2018, North Africa accounted for 22% of Eni's total worldwide production of oil and natural gas.

Algeria. In April 2018, Eni signed a framework agreement with Sonatrach to revamp exploration and development activities in the Berkine area. The agreement covered the following items: (i) in July 2018 defined an agreement for upgrading existing facilities of the BRN fields in the Block 403 (Eni operator with a 50% interest) and of the MLE fields in the Block 405b (Eni operator with a 75% interest) leveraging on synergies with the new forthcoming facilities. The agreement also includes the construction of pipeline to link the BRN fields with the MLE assets targeting to transform the area in a gas hub; and (ii) in October 2018 signed an agreement to assign to Eni a 49% interest in the Sif Fatima II, Zemlet El Arbi and Ourhoud II concessions, in the North Berkine area. Management plans an exploration campaign and fast-track development activities. Start-up is expected in the third quarter of 2019 leveraging on the completion of the BRN-MLE pipeline that will link the BRN associated gas as well as associated gas and condensates of the Berkine North development project to the MLE treatment facilities. In addition, Eni and Total signed two partnership agreements for an exploration campaign in the offshore Algeria. In December 2018, two exploration permits were assigned to launch a seismic data acquisition in 2019.

Development activities concerned: (i) production optimization at the ROM North (Eni's interest 35%) and ROD (Eni's interest 55%) operated fields as well as in the non-operated Block 404 (Eni's interest 12.25%); (ii) drilling activities in the Block 405b at the CAFC Oil and MLE projects as well as upgrading activity of existing treatment facilities; and (iii) progress in the development program of the El Merk field in the Block 208 (Eni's interest 12.25%) with the drilling of production and water injection wells.

Libya. In recent years, Eni's petroleum activities in Libya have been negatively affected by the unstable political and social framework of the Country. Currently, Libya represents approximately 17% of the Group's total production; although this proportion is forecasted to decrease in the medium term, the Libya situation remain an area of issue. For further information on this matter, see "Item 3 – Risk factors – Political considerations".

The rights to produce of Eni's assets in Libya will expire in 2038 for Contract Area C, in 2041 for Contract Area E, in 2042 for Contract Area A and B as well as in 2043 for Contract Area D production

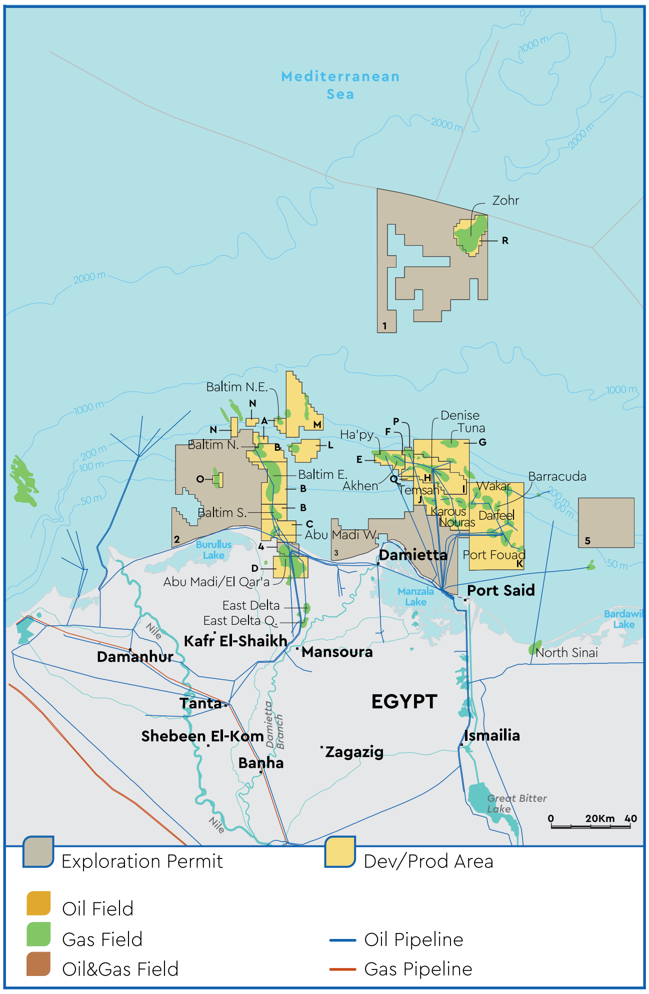
In 2018, Eni finalized an agreement with NOC oil state company and BP to award a 42.5% interest and the operatorship in the BP contractual areas, in particular in the onshore Area A and Area B and in the offshore Area C. The agreement provides for a revamp exploration and development activities in the Country leveraging on Eni's facilities existing in the areas.

During the year, development activities concerned: (i) production start-up of the Bahr Essalam Phase 2 offshore project (Eni's interest 50%) where the planned activities progressed and the completion is expected in the second quarter of 2019. The development plan provided for drilling ten wells, out of which seven were completed and started up in 2018, as well as upgrading the existing facilities to increase production capacity; (ii) upgrading of treatment plants at the Mellitah area (Eni's interest 50%) and at the Sabratha platform (Eni's interest 50%); and (iii) a production optimization plan at the Wafa field. The activity provided for drilling additional wells and the construction of new compression units. In particular, the infilling wells campaign started in 2018: a first gas well was completed in November 2018 and a second one in March 2019. The project is expected to be completed in 2019.

Morocco. In March 2019, Eni signed an agreement to divest a 30% interest in the Tarfaya Offshore Shallow exploration license to Qatar Petroleum, retaining the operatorship of the permit with a 45% interest. The agreement is subject to approval by relevant Authorities.

Tunisia. Development activities concerned production optimization at the producing concessions to mitigate mature fields declines.

Egypt



In 2018, Egypt accounted for 16% of Eni's total worldwide production of oil and natural gas.

In February 2019, Eni was awarded two onshore exploration blocks: (i) a 100% interest in the South East Siwa block in the western desert nearby to the South West Meleiha concession (Eni's interest 100%); and (ii) the operatorship with a 50% interest in the West Sherbean block in the onshore Nile Delta nearby to the operated Nooros producing fields (Eni's interest 75%).

In June 2018, Eni completed the disposal of a 10% interest of the Zohr project (Eni's interest 50%) to Mubadala Petroleum, for a cash consideration of $934 million.

In August 2018, Egyptian Authority approved the following agreements: (i) Eni was awarded an 85% interest in the Nour exploration license in the eastern offshore Nile Delta. In December 2018, Eni divested a 20% and 25% interest of Nour license to Mubadala Petroleum and BP, respectively. Currently Eni holds 40% interest; (ii) ten years extension from 2021 of the Nile Delta concession (Eni's interest 75%) which includes Abu Madi West concession with Nooros producing field; (iii) an extension of exploration campaign in the El Qar'a permit (Enis' interest 75%), which is located in the Great Nooros producing area; (iv) five years extension of the Ras Qattara concession (Eni's interest 75%) in the western desert; and (v) an extension of the Faramid development lease (Enis' interest 100%).

In September 2018, the Zohr project achieved the targeted production plateau of 365 KBOE/d (110 KBOE/d net to Eni) with the completion of the drilling activities and the construction and commissioning of the planned four gas treatment units onshore in addition to the one started at the end of 2017, which increased available treatment capacity to more than 2.1 BCF/d. Management plans to step up the production plateau to 3.2 BCF/d during 2019 by building and commissioning other three gas treatment units and by drilling three additional production wells to reach 13 production wells.

As of December 31, 2018, the aggregate development costs incurred by Eni for the Zohr project capitalized in the financial statements amounted to $4.3 billion (€3.8 billion at the EUR/USD exchange rate of December 31, 2018). The planned capital expenditures to support continuing production ramp-up at the Zohr field in the next four-year period will be financed through net cash provided by operating activities at the Eni Brent marker scenario.

As of December 31, 2018, Eni's proved reserves booked for the Zohr field amounted to 782 mmBOE. The Zohr proved reserves, both developed and undeveloped, are related to the project phase 1 only.

Development activities at other Eni's fields in Egypt concerned: (i) the Baltim South West project (Eni operator with a 55% interest) in the offshore of the Country. The project sanctioned in 2018 and start-up is expected during 2019; (ii) the completion and start-up of two additional productive wells of the Nooros field (Eni operator with a 75% interest) and the construction of a pipeline for transporting gas to the treatment plan of El Gamil. The completion of the activities is expected in 2019; and (iii) infilling activities and production optimization in the operated Sinai (Eni's interest 100%), Meleiha (Eni's interest 76%) and Ras Qattara (Eni's interest 75%) concessions.

Exploration activities yielded positive results with: (i) the Faramid-S1X gas well in the East Obayed concession (Eni's interest 100%); (ii) the A-2X and B1-X oil discoveries and the A-1X gas and condensates discovery in the South West Meleiha concession; and (iii) the Nour-1 gas well in the Nour exploration license.

Sub-Saharan Africa

Eni's operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Ghana, Mozambique and Nigeria. In 2018, Sub-Saharan Africa accounted for 19% of Eni's total worldwide production of oil and natural gas.

Angola. In November 2018, Eni signed an amendment of the Block 15/06 PSA contract (Eni operator with a 36.84% interest) that defines an additional exploration acreage in the western area of the block.

Development activities mainly concerned the two producing projects in the Block 15/06. In particular, activity of the West Hub project included: (i) production ramp-up of the Ochigufu field was achieved with a production plateau of 25 KBBL/d; and (ii) production start-up of the Vandumbu field. In the East Hub project development activities concerned: (i) production start-up of UM8 field with the linkage to FPSO exisisting in the area; (ii) upgrading of certain production facilities; and (iii) the Cabaça North & Cabaça South-East UM4/5 projects were sanctioned; the development plan foreseen the drilling of three productive wells, two water injection wells and the connection to the existing production facilities in the area. Start-up is expected in 2021.

Planned drilling activities were completed at the Mafumeira Sul producing field in the Block 0 (Eni's interest 9.8%).

Eni owns a 13.6% interest of Angola LNG, which runs the plant, located in Soyo, with a treatment capacity of approximately 350 BCF/y of feed gas and a liquefaction capacity of 5.2 mmtonnes/y of LNG. In 2018 production net to Eni averaged approximately 20 KBOE/d.

Exploration activities have given positive results with the Kalimba and Afoxé oil discoveries in the East Hub project area as well as the Agogo oil discovery in the West Hub project area.

Congo. Development activity carried out in 2018 related to: (i) the Nené Marine Phase 2A producing project in the Marine XII block (Eni operator with a 65% interest) with the completion of drilling activities and the installation of a sealine for the connection to the Litchendjili field production platform in the Marine XII block; and (ii) the completion of engineering activities of the Nené Marine phase 2B project. The project was sanctioned in December 2018.

Ghana. In 2018, the non-associated gas production started up at the operated Offshore Cape Three Points (OCTP) project (Eni's interest 44.44%). The gas production is sent to an onshore treatment plant to feed the national grid.

The Offshore Cape Three Points license expires in 2036.

Eni also operates the offshore exploration license Cape Three Points Block 4 (Eni's interest 42.47%).

Mozambique. Eni has been present in Mozambique since 2006, following the award of the exploration license relating to gas-rich Area 4 Offshore of the Rovuma Block.

In 2011, Eni made the important gas discovery of Mamba. The Mamba reservoir extends through Area 4 and the adjacent Area 1 operated by Anadarko. In 2012, Eni made the important Coral gas discovery, which falls entirely in Area 4.

During the exploration period, which expired in 2015, six Discovery Areas (DA) were identified. Mozambique Decree Law 02/2014 provides that individual plans of development can be submitted in respect of each DA. Under the Area 4 EPCC (Exploration and Production Concession Contract), each Plan of Development once approved by the Government of Mozambique entitles the Concessionaires to develop and to produce in a term of 30 years, with an extension option pursuant to the terms of the Area 4 EPCC and the applicable Petroleum Law.

Following two separate transactions occurred respectively in 2013 and in 2017, Eni divested to CNPC and Exxon Mobil indirect interests of 20% and 25% respectively in the discoveries of Area 4, by diluting its participating interest in Mozambique Rovuma Venture SpA, the operator of Area 4. Past transactions, Eni retains a 25% indirect interest in the Area 4 concession. The other concessionaires of Area 4 are the state-owned oil company ENH, Galp and Kogas, each with a 10% working interest.

Development activities continued at the Coral South Floating LNG project during 2018, which is operated by Eni. The LNG produced will be sold by the Area 4 Concessionaires to BP under a long-term contract for a period of twenty years, with an option for an additional ten-year term.

Pre-Development activities progressed at the Mamba Complex discoveries where Eni is operator of the upstream development phase and Exxon Mobil leads the construction and operation phase of natural gas liquefaction facilities onshore. The Mozambique authorities expressed their intent to unitize the reservoir that straddles Area 4 and Area 1. In the meantime, pending a final determination of the unitization, the Concessionaires of Area 4 are entitled to develop part of the reserves contained in the reservoir that straddles the two areas on condition that the two operators will coordinate their activities.

In this context, the Area 4 Concessionaire progressed activities to made the final investment decision (FID) for the Rovuma LNG project, which provides the construction of two onshore LNG trains with capacity of approximately 7.6 mmtonnes/y each, feed by 24 subsea wells, the gas treatment, the liquefaction, the storage and the export of LNG. In July 2018, the plan of development (PoD) was submitted to the relevant Authorities for their initial review. The activities progressed with the finalization of the PoD, of preliminary long-term agreements for the purchase of LNG volumes and the project financing. The Final Investment Decision is expected in 2019 with start-up in 2024.

In October 2018 Eni signed the contract for the exploration and development rights of the offshore block A5-A, in the deep offshore of Zambesi. Eni was awarded the operatorship of the block with a 59.5% interest. In March 2019, Eni signed a farm out agreement with Qatar Petroleum to divest a 25.5% interest in the block. The transaction is subjected by approval of the relevant Authority.

Nigeria. Development activities mainly included: (i) workover and rigless activities to support current production as well as maintenance and restoration of damaged facilities due to sabotage and bunkering in the operated OML60, 61, 62 and 63 blocks (Eni's interest 20%); (ii) drilling activities to increase production and workover activities to mitigate mature field decline in the OML 118 block (Eni's interest 12.5%) and in the operated OML 125 block in the Abo field (Eni's interest 100%); and (iii) associated gas program of Forkados Yokri Integrated Project in the OML 43 block (Eni's interest 5%) as well as Gbaran phase 2A/2B and SSAGS project in the OML 28 block (Eni's interest 5%). Gas production will be sold to the local market.

Eni holds a 10.4% interest in the Nigeria LNG Ltd joint venture, which runs the Bonny liquefaction plant located in the Eastern Niger Delta. The plant has treatment capacity of approximately 1,236 BCF/y of feed gas and a production capacity of 22 mmtonnes/y of LNG. Natural gas supplies to the plant are currently provided under a gas supply agreements from the SPDC JV (Eni's interest 5%), TEPNG JV and the NAOC JV (Eni's interest 20%). In 2018, the Bonny liquefaction plant processed approximately 1,130 BCF. LNG production is sold under long-term contracts and exported to the United States, Asian and European markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG.

Exploration activities yielded positive results with the EPU-05 deep offshore gas discovery in the Gbaran-Kolo Creek-Epu area (Eni's interest 5%).

In the exploration phase Eni operates offshore OML 134 (Eni's interest 100%), OPL 2009 (Eni's interest 49%), and onshore OPL 282 (Eni's interest 90%) and OPL 135 (Eni's interest 48%). Eni also holds a 12.5% interest in non-operated OML 135.

The acquisition of the OPL 245 property made by Eni in 2011 is the subject of certain judicial proceedings describe in "Item 18 – consolidated financial statement – Note 27".

Kazakhstan

Eni's operations in Kazakhstan mainly regards the Kashagan and the Karachaganak fields. In 2018, Kazakhstan accounted for 8% of Eni's total worldwide production of oil and natural gas.

Kashagan. Eni holds a 16.81% working interest in the North Caspian Sea Production Sharing Agreement (NCSPSA). The NCSPSA defines terms and conditions for the exploration and development of the Kashagan field, which was discovered in the Northern section of the contractual area in the year 2000 over an area extending for 4,600 square kilometers. Management believes this field contains a large amount of hydrocarbon resources, which will eventually be developed in phases. The NCSPSA expires at the end of 2041.

In addition to Eni, the partners of the Consortium are the Kazakh national oil company, KazMunayGas, with a participating interest of 16.88%, the international oil companies Total, Shell and ExxonMobil, each with a participating interest of 16.81%, CNPC with 8.33%, and Inpex with 7.56%.

In 2018, production of the Kashagan field averaged 47 KBBL/d net to Eni of liquids and 58 mmCF/d net to Eni of natural gas. The treated gas is delivered to the national gas marketing and transportation company (KazTransGas), and the remaining volumes is utilized as fuel gas for internal use. The remaining untreated gas volumes (approximately 30%) is re-injected in the reservoir. The liquid production is stabilized at Bolashak facilities and exported to Western markets through the Caspian Pipeline Consortium (Eni's interest 2%) and the Atyrau-Samara pipeline.

In 2019, Experimental Program development of the field is expected to lead to plateau oil production capacity of about 370 KBBL/d, on a 100% basis. Additional phases of development are being studied, which contemplate increasing gas injection capacity, the conversion of production wells into injection wells and the upgrading of the existing facilities.

Management believes that significant capital expenditures will be required in case the partners of the venture would sanction a second development phase and possibly other additional phases. Eni will fund those investments in proportion to its participating interest of 16.81%. However, taking into account that future development expenditures will be incurred over a long time horizon and subsequent to the production start-up, management does not expect any material impact on the Company's liquidity or its ability to fund these capital expenditures.

As of December 31, 2018, Eni's proved reserves booked for the Kashagan field amounted to 614 mmBOE, slightly decreased from 620 mmBOE in 2017.

As of December 31, 2018, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.9 billion (€8.6 billion at the EUR/USD exchange rate of December 31, 2018). This capitalized amount included: (i) $7.3 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.6 billion relating primarily to accrued finance charges and expenditures for the acquisition of interests in the Consortium from exiting partners upon exercise of pre-emption rights in previous years.

Karachaganak. Located onshore in West Kazakhstan, Karachaganak is a liquid and gas field. Operations are conducted by the Karachaganak Petroleum Operating consortium (KPO) and are regulated by a PSA lasting 40 years, until 2037. Eni and Shell are co-operators of the venture. Eni's interest in the Karachaganak project is 29.25%.

In 2018, production of the Karachaganak field averaged 44 KBBL/d net to Eni of liquids and 170 mmCF/d net to Eni of natural gas. This field is developed by producing liquids from the deeper layers of the reservoir. The gas is marketed (about 50%) at the Russian gas plant in Orenburg and the remaining volumes is utilized for re-injecting in the higher layers and the production of fuel gas. Approximately 95% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) and exported to Western markets through the Caspian Pipeline Consortium (Eni's interest 2%) and the Atyrau-Samara pipeline. The remaining volumes of non-stabilized liquid production was marketed at the Russian terminal in Orenburg until September 2018, when the purchase agreement expired.

Within the gas treatment expansion projects of the Karachaganak field, the Karachaganak Process Center Debottlenecking project was sanctioned. Activity progressed with completion expected in 2020. Additional re-injection capacity will be ensured by installing a new re-injection facility in addition to the existing ones.

As of December 31, 2018, Eni's proved reserves booked for the Karachaganak field amounted to 452 mmBOE, reporting a decrease of 78 mmBOE from 2017 mainly due to an increased marker Brent price used in the reserves estimation process.

Rest of Asia

In 2018, Eni's operations in the Rest of Asia accounted for 9% of its total worldwide production of oil and natural gas.

Bahrain. In January 2019, Eni signed a Memorandum of Understanding with the National Oil and Gas Authority of the Kingdom of Bahrain (NOGA). The agreement includes an exploration program for the offshore Block 1.

China. Eni has been present in China since 1984 with activities located in the South China Sea.

In 2018, hydrocarbons were produced from the offshore Blocks 16/19 through 3 platforms connected to an FPSO.

Indonesia. Activities are concentrated in the offshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 13 blocks.

In May 2018, Eni was awarded a 100% interest in the East Ganal exploration block in the deep offshore Kutei area nearby the operated Muara Bakau block (Eni's interest 55%).

In 2018, within the portfolio rationalization, Eni divested entire interest in the Sanga Sanga permit.

Development activities concerned the offshore Merakes gas project in the operated East Sepinggan block (Eni's interest 85%). In December 2018, the development plan was sanctioned by relevant Authorities. The project provides for the drilling of five subsea wells, which will be linked to the Floating Production Unit (FPU) of the Jangkrik producing fields (Eni operator with a 55% interest). Natural gas production is processed by the FPU and then delivered by pipeline to the onshore plant, which is linked to the East Kalimantan transport system to feed Bontang liquefaction plant or will be sold on a spot basis in the domestic market. Start-up is expected in 2020.

Exploration activities yielded positive results with the Merakes East discovery in the operated East Sepinggan block.

Iraq. Development activities concerned the execution of an additional development phase of the ERP (Enhanced Redevelopment Plan) for the Zubair field, to achieve a production plateau of 700 KBBL/d. This phase also contemplates utilization of the associated gas for power generation. The production capacity and relevant facilities to treat the targeted production plateau have been already installed; the field reserves will be progressively put into production by drilling additional productive wells over the next few years.

Lebanon. In February 2018, Eni signed two Exploration and Production Agreements (EPA) with the Republic of Lebanon including Blocks 4 and 9, located in the deep-offshore Lebanon. Eni owns a participating interest of 40% in each block.

Myanmar. Eni has been present in Myanmar since 2014. Eni is operator of four Production Sharing Contracts; two onshore blocks RSF-5 and PSC-K (Eni's interest 90% in both leases) and two offshore blocks MD-02 and MD-04 (Eni's interest 40% in both leases).

Oman. Eni has been present in Oman since 2017. Eni operates the Block 52, located offshore Oman. In January 2018, the relevant Authorities of the country approved the farm out agreement signed in 2017 with the Qatar Petroleum oil company. Eni retains the operatorship of the block with a 55% interest.

In January 2019, Eni was awarded the exploration Block 47 and signed a Head of Agreement for the exploration Block 77, located onshore Oman. Eni will operate both blocks with a 90% interest and 50% interest, respectively.

Pakistan. In 2018, development activities concerned production optimization through drilling activities of new wells, optimization of onshore existing facilities and rigless activity of productive wells to mitigate the natural fields production decline.

Russia. Eni is present in Russia through two joint ventures with Rosneft, which retain the exploration licenses relating to the Fedynsky and the Central Barents areas respectively (Eni's interest 33.33%) in the Russian Barents Sea.

In July 2018, following unsuccessful exploration activity, Eni relinquished the Western Chernomorsky license (Eni's interest 33.33%) in the Black Sea.

There are no ongoing, nor planned exploration activities in the Country.

The Russia upstream sector is the target of certain international sanctions that are described in "Item 3 – Risk factors".

Turkmenistan. Activities are focused on the onshore Nebit Dag Area (Eni operator with a 90% interest) in the Western part of the country. The license expires in 2032.

Production derives mainly from the Burun oil field. Oil production is shipped to the Turkmenbashi refinery plant. Eni receives, by means of a swap arrangement with the Turkmen Authorities, an equivalent amount of oil at the Okarem terminal, close to the South coast of the Caspian Sea. Eni's entitlement is sold FOB. Associated natural gas is used for gas lift system. The remaining amount is delivered to the national oil company Turkmenneft, via national grid.

Drilling activities of new wells and workover program represent main activities currently performed in the area to mitigate the natural field production declines.

United Arab Emirates. In March 2018, Eni signed with the Supreme Petroleum Council (SPC) and the Abu Dhabi National Oil Company (ADNOC) two Concession Agreements related to the acquisition of a 5% participating interest in the Lower Zakum oil field and a 10% participating interest in the Umm Shaif and Nasr oil, condensates and natural gas fields, in the offshore of Abu Dhabi, for a consideration of \$875 million with duration of 40 years.

In November 2018, Eni was awarded a 25% interest in the Ghasha offshore concession with duration of 40 years. The concession includes the Hail, Ghasha and Dalma gas discoveries and certain offshore fields in the Al Dhafra area. Production start-up is expected in 2022.

In January 2019, Eni was awarded the operatorship of the Block 1 and 2 with a 70% interest, located offshore Abu Dhabi. The exploration commitment for the first phase consists in exploration studies for the Block 1 and the drilling of two exploration wells and two appraisal wells in the Block 2.

In January 2019 Eni was awarded three onshore exploration concessions in the Emirate of Sharjah: (i) the operatorship with a 75% interest in the concession Area A and C; and (ii) a 50% interest in the concession Area B. The exploration commitment of first phase includes the drilling of one exploration well and exploration studies in concessions Area A and B as well as exploration studies in Area C.

Vietnam. Eni has been present in Vietnam since 2012 and is operator of five offshore Production Sharing Contracts, two of which are held with 100% interest (Block 116 and Block 122) and three are in Joint Venture (Block 114 – Eni's interest 50%, Block 120 – Eni's interest 66.67%, Block 124 – Eni's interest 60%).

Americas

In 2018, Eni's operations in the Americas area accounted for 7% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988. Operations are performed in Block 10 (Eni's interest 100%) located in the Oriente Basin, in the Amazon forest.

Exploration and production activities in Ecuador are regulated by a service contract that expires in 2033.

Block 10 production is processed by a Central Production Facility and transported to the Pacific Coast through a pipeline network. Eni is planning to divest its entire working interest in Block 10.

Mexico. Eni has been present in Mexico since 2015. Eni's activities are concentrated in the Gulf of Mexico. Eni is operator of: (i) the offshore Area 1 license (Eni's interest 100%) where the development activities of the Amoca, Miztón and Tecoalli discoveries progressed aiming at starting production in 2019; and (ii) the Area 10 (Eni's interest 100%), the Area 14 (Eni's interest 60%) and the Area 7 (Eni's interest 45%) exploration licenses located in the Sureste basin.

Furthermore, in 2018, Eni was awarded the operatorship with a 65% interest of the Area 24 license and with 75% of the Area 28 license.

Exploration and production activities in Mexico are regulated by PSA and concession contract for the Area 24 license.

In 2018, Eni signed an agreement with Lukoil to swap interests in three exploration licenses. Based on the agreement which approval is to be ratified by local Authorities, Eni will divest its 20% interest in Area 10 and Area 14 licenses and will purchase a 40% interest in Area 12 license operated by Lukoil.

In July 2018 the Plan of Development (PoD) for the Amoca, Mitzón and Tecoalli discoveries was approved by the Mexican Authorities. The phased approach for the development plan includes an early production start-up in 2019 through the installation of a production platform and the realization of facilities to connect the platform to an onshore existing treatment plant, with a production of 8 KBBL/d. The full field development envisages a phased installation of three additional platforms and a FPSO, which will increase the production capacity up to 90 KBBL/d in 2021. In December 2018, Eni agreed to divest its 35% interest of the Area 1 to Qatar Petroleum Company. The agreement is awaiting approval from the local Authorities.

Trinidad and Tobago. In 2018, Eni divested its entire interest of upstream activities in the Country.

United States. Eni holds interests in 62 exploration and production blocks in the Gulf of Mexico, of which 26 are operated by Eni.

Development activities concerned the Lucius Subsequent Development (Eni's interest 8.5%) with the drilling and completion of three submarine productive wells, which will be linked to the production platform of the Lucius field and upgrading of existing facilities.

To achieve the highest safety standards of its operations, Eni is a member of the HWCG Consortium of Gulf of Mexico operators. The HWCG provides resources, coordination and performs certain activities associated with underwater containment of erupting wells, evacuation of hydrocarbon on the sea surface, storage and transport to the coastline. For further information on this matter, see "Item 3 – Risk factors".

In August 2018, Eni was awarded a 100% interest of 124 licenses in Alaska. Eni currently performed its activity in 166 exploration and development blocks in Alaska.

In December 2018, Eni signed an agreement to purchase of 70% interest and the operatorship of the Ooguruk field, where Eni already holds 30% interest. The agreement has been finalized in 2019.

Venezuela. Eni's activity is located in the Gulf of Venezuela and Gulf of Paria and onshore in the Orinoco Oil Belt.

In 2018, Eni's production of oil and natural gas averaged 47 KBOE/d and accounted for approximately 3% of Eni's total production.

Eni's production comes from the Perla gas field (Eni's interest 50%), in the Gulf of Venezuela, the Corocoro field (Eni's interest 26%), in the Gulfo de Paria, and the Junin 5 oil field (Eni's interest 40%), located in the Orinoco Oil Belt.

Eni is also participating with a 19.5% interest in Petrolera Güiria for oil exploration and with a 40% interest in Punta Pescador and Gulfo de Paria Ovest for gas exploration, both located offshore in the eastern Venezuela.

Australia and Oceania

Eni's operations in Australia and Oceania area are conducted mainly in Australia. In 2018, the area of Australia and Oceania accounted for 1% of Eni's total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2001. Activities are focused on offshore fields.

The main production blocks in which Eni holds interests are WA-33-L (Eni's interest 100%) and JPDA 03-13 (Eni's interest 10.99%). In the appraisal and development phase, Eni holds interests in NT/RL8 (Eni's interest 100%) and the operatorship of NT/RL7 (Eni's interest 65%). In addition, Eni holds interest in 4 exploration licenses, of which 1 in the JPDA.

Capital expenditures

See "Item 5 – Liquidity and capital resources – Capital expenditures by segment"

Disclosure pursuant to Section 13(r) of the Exchange Act

The Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) created a new subsection (r) in Section 13 of the Exchange Act which requires a reporting issuer to provide disclosure if the issuer or any of its affiliates engaged in certain enumerated activities relating to Iran, including activities involving the Government of Iran. In accordance with our general business principles and Code of Ethics, Eni seeks to comply with all applicable international trade laws including applicable sanctions and embargoes. The activities referred to below have been conducted outside the U.S. by non-U.S. Eni subsidiaries. For purposes of the disclosure below, amounts have been converted into U.S. dollars at the average or spot exchange rate, as appropriate.

In 2017, Eni fully recovered the overdue trade receivable owed by Iranian state-owned companies relating to the cost recovery of past projects due to enactment of the agreements signed in 2016. There were not any outstanding trading receivables towards Iran's national oil companies as of December 31, 2018. In 2018, Eni made payments in the region of $0.6 million to the Iranian Social Security Organization in connection to health and social security insurance for which Eni retains at December 31, 2018 a residual payable amounting to approximately $5 million, which will be settled upon de-registration of our local branch.

Gas & Power

Eni's Gas & Power segment engages in supply, trading and marketing of gas and electricity, international transport, and LNG supply/marketing and trading. This segment also includes the activities of electricity generation. In 2018, Eni's worldwide sales of natural gas amounted to 76.71 BCM. Sales in Italy amounted to 39.03 BCM, while sales in European markets were 29.42 BCM that included 3.42 BCM of gas sold to certain importers to Italy.

The business results of operations in 2018 and its strategy are described in "Item 5 – 2016 – 2018 Group results of operations" and "Item 5 – Management's expectations of operations."

Supply of natural gas

In 2018, Eni's total supply of natural gas was 74.15 BCM, down by 4.13 BCM, or 5.3% from 2017. Gas volumes supplied outside Italy (68.82 BCM from consolidated companies), imported in Italy or sold outside Italy, represented approximately 93% of total supplies, down by 4.41 BCM, or 6% compared to the previous year, due to lower volumes purchased in Russia (down by 1.85 BCM), in the Netherlands (down by 1.25 BCM) in Algeria (down by 1.16 BCM) and in Norway (down by 0.73) partially offset by higher purchases in Indonesia (up by 2.32 BCM) and in Qatar (up by 0.20 BCM).

Supplies in Italy (5.33 BCM) increased by 5.5% from 2017 due to higher equity production.

In 2018, main gas volumes from equity production derived from: (i) Italian gas fields (3.9 BCM); (ii) certain Eni fields located in the British and Norwegian sections of the North Sea (2.6 BCM); (iii) Indonesia (1.6 BCM); (iv) Libyan fields (1.4 BCM); (v) the United States (0.3 BCM).

Supplied gas volumes from equity production were approximately 9.9 BCM representing 13% of total volumes available for sale.

The table below sets forth Eni's purchases of natural gas by source for the periods indicated.

Natural gas supply	**2018**	**2017**	**2016**
		(BCM)	
Italy	**5.33**	**5.05**	**6.00**
Outside Italy	**68.82**	**73.23**	**76.64**
Russia	26.24	28.09	27.99
Algeria (including LNG)	12.02	13.18	12.90
Libya	4.55	4.76	4.87
the Netherlands	3.95	5.20	9.60
Norway	6.75	7.48	8.18
the United Kingdom	2.21	2.36	2.08
Indonesia (LNG)	3.06	0.74	
Qatar (LNG)	2.56	2.36	3.28
Other supplies of natural gas	5.52	6.75	5.83
Other supplies of LNG	1.96	2.31	1.91
Total supplies of subsidiaries	**74.15**	**78.28**	**82.64**
Withdrawals from (input to) storage	0.08	0.31	1.40
Network losses, measurement differences and other changes	(0.18)	(0.45)	(0.21)
Volumes available for sale of Eni's subsidiaries	**74.05**	**78.14**	**83.83**
Volumes available for sale of Eni's affiliates	**2.66**	**2.69**	**2.48**
Total volumes available for sale	**76.71**	**80.83**	**86.31**

Sales of natural gas

Eni is selling gas to wholesale and retail markets in Italy and in a number of European countries. The wholesale market includes sales to large accounts (industrials and thermoelectric utilities) and on European spot markets. The retail segment includes sales to residential customers (households and larger accounts like hospitals, schools, office buildings) and small and medium-sized businesses located in urban areas. The Company has grown the combined offer of gas and electricity to retail customers to maximize cross-selling opportunities and cost synergies.

In 2018, natural gas sales amounted to 76.71 BCM (including Eni's own consumption, Eni's share of sales made by equity-accounted entities), representing a decrease of 4.12 BCM, or 5.1% from the previous year. Sales in Italy (39.03 BCM) increased by 4.3% from 2017. Higher sales to spot market and volumes sold to wholesalers and industries were partly offset by lower sales to thermoelectrical and residential segments. Sales in the European markets amounted to 26 BCM, a decrease of 24.3% or 8.34 BCM from 2017.

Sales to long-term buyers were down by 12.1% compared to the previous year due to the shorter availability of Libyan output. Sales in the Extra European markets (8.26 BCM) increased by 3.09 BCM or 59.8% due to higher LNG sales in Japan, Pakistan, China and Taiwan, partly offset by higher volumes sold in South Korea and India.

The tables below set forth Eni's sales of natural gas by principal market for the periods indicated.

Natural gas sales by entities	2018	2017	2016
		(BCM)	
Total sales of subsidiaries	**73.70**	**77.52**	**83.34**
Italy (including own consumption)	**39.03**	**37.43**	**38.43**
Rest of Europe	27.58	36.10	40.52
Outside Europe	7.09	3.99	4.39
Total sales of Eni's affiliates (Eni's share)	3.01	3.31	2.97
Italy			
Rest of Europe	1.84	2.13	1.91
Outside Europe	1.17	1.18	1.06
Worldwide gas sales	**76.71**	**80.83**	**86.31**

Natural gas sales by market	2018	2017	2016
		(BCM)	
ITALY	**39.03**	**37.43**	**38.43**
Wholesalers	9.15	8.36	7.93
Italian gas exchange and spot markets	12.49	10.81	12.98
Industries	4.79	4.42	4.54
Medium-sized enterprises and services	0.79	0.93	1.72
Power generation	1.50	2.22	0.77
Residential	4.20	4.51	4.39
Own consumption	6.11	6.18	6.10
INTERNATIONAL SALES	**37.68**	**43.40**	**47.88**
Rest of Europe	**29.42**	**38.23**	**42.43**
Importers in Italy	3.42	3.89	4.37
European markets	26.00	34.34	38.06
Iberian Peninsula	4.65	*5.06*	*5.28*
Germany/Austria	1.83	*6.95*	*7.81*
Benelux	5.29	*5.06*	*7.03*
Hungary			*0.93*
United Kingdom/Northern Europe	2.22	*2.21*	*2.01*
Turkey	6.53	*8.03*	*6.55*
France	4.95	*6.38*	*7.42*
Other	0.53	*0.65*	*1.03*
Extra European markets	**8.26**	**5.17**	**5.45**
WORLDWIDE GAS SALES	**76.71**	**80.83**	**86.31**

The LNG business

Eni LNG business can count currently on a portfolio of contracted long-term supplies mainly from Indonesia, Qatar, Nigeria, Oman and Algeria. In the plan period, Eni intends to develop its LNG business leveraging on the integration with the E&P segment and the valorization of the equity gas. Final markets of that gas include Europe, China, Japan, Pakistan and Taiwan.The business's profitability will be also driven by enhancing the commercial presence in premium markets and continuing integration with trading activities.

LNG sales	2018	2017	2016
		(BCM)	
G&P sales	**10.3**	**8.3**	**8.1**
Rest of Europe	4.7	5.2	5.2
Extra European markets	5.6	3.1	2.9

Electricity sales and power generation

Electricity sales

As part of its marketing activities in Italy, Eni engages in selling electricity on the Italian market principally on the open market, on the Italian Stock Exchange for electricity and at industrial sites. Supplies of electricity include both own production volumes through gas-fired, combined-cycle facilities and purchases on the open market. This activity has been developed in order to capture further value along the gas value chain leveraging on the Company's large gas availability. In addition, with the aim of developing and retaining valuable customers in the residential space and small and middle business located in urban area, the Company has developed a commercial offer that provides the combined supply of gas and power to the retail market in Italy and in France.

In 2018, power sales (37.07 TWh) were directed to the free market (70%), the Italian Power Exchange (19%), industrial sites (10%) and others (1%). Compared to 2017, electricity sales in the free market were down by 0.62 TWh or by 2.3%, due to lower volumes sold to large customers, middle market and small and medium-sized enterprises, partially offset by higher volumes sold to the wholesalers segment.

Power availability	2018	2017	2016
		(TWh)	
Power generation sold	21.62	22.42	21.78
Trading of electricity[a]	15.45	12.91	15.27
	37.07	**35.33**	**37.05**
Power sales by market			
Free market[a]	25.91	26.53	27.49
Italian Exchange for electricity	7.17	5.21	5.64
Industrial plants	3.49	3.01	3.11
Other[a]	0.50	0.58	0.81
	37.07	**35.33**	**37.05**

(a) Include positive and negative imbalances (differences between power introduced in the grid and the one planned).

Power generation

Eni's power generation sites are located in Ferrera Erbognone, Ravenna, Mantova, Brindisi, Ferrara and Bolgiano. In 2018, power generation was 21.62 TWh, down by 0.80 TWh or by 3.6% from 2017. As of December 31, 2018, installed operational capacity was 4.7 GW, unchanged compared to December 31, 2017. Electricity trading (15.45 TWh) reported an increase of 19.7% thanks to the optimization of inflows and outflows of power.

Site	Total installed capacity in 2018 (GW)	Technology	Fuel
Brindisi	**1.3**	CCGT	gas
Ferrera Erbognone	**1.0**	CCGT	gas/syngas
Mantova	**0.8**	CCGT	gas
Ravenna	**1.0**	CCGT	gas
Ferrara[(a)]	**0.4**	CCGT	gas
Bolgiano	**0.1**	Power station	gas
	4.7		

(a) Eni's share of capacity.

Power generation		**2018**	**2017**	**2016**
Purchases				
Natural gas	(mmCM)	4,300	4,359	4,334
Other fuels	(ktoe)	356	392	360
- *of which steam cracking*		94	104	105
Production				
Electricity	(TWh)	21.62	22.42	21.78
Steam	(ktonnes)	7,919	7,551	7,974
Installed generation capacity	(GW)	**4.7**	**4.7**	**4.7**

International transport

Eni has transport rights on a large European network of integrated infrastructures for transporting natural gas, which links key consumption markets with the main producing areas (Algeria, Libya and the North Sea). Eni has contracted the transport capacity under ship-or-pay contracts, which are similar to take-or-pay contracts.

Eni also retains ownership interests in certain pipeline companies, which run and operate the facility by selling transportation capacity under long-term ship-or-pay contracts to both shareholders and third party shippers. The main assets of Eni's transport activities are provided in the table below.

International Transport infrastructure Route

	Lines	Total length	Diameter	Transport capacity[(1)]	Transit capacity[(2)]	Compression stations
	(units)	(km)	(inch)	(BCM/y)	(BCM/y)	(No.)
TTPC (Oued Saf Saf-Cap Bon)	2 lines of km 370	740	48	34.3	33.2	5
TMPC (Cap Bon-Mazara del Vallo)	5 lines of 155	775	20/26	33.5	33.5	
GreenStream (Mellitah-Gela)	1 line of km 520	520	32	8.0	8.0	1
Blue Stream (Beregovaya-Samsun)	2 lines of km 387	774	24	16.0	16.0	1

(1) Includes both transit capacity and volumes of natural gas destined to local markets and withdrawn at various points along the pipeline.
(2) The maximum volume of natural gas which is input at various entry points along the pipeline and transported to the next pipeline.

International transport activities

The TTPC pipeline, 740-kilometer long, is made up of two lines that are each 370-kilometers long with a transport capacity of 34.3 BCM/y and five compression stations. This pipeline transports natural gas from Algeria across Tunisia from Oued Saf Saf at the Algerian border to Cap Bon on the Mediterranean coast where it links with the TMPC pipeline.

The TMPC pipeline for the import of Algerian gas is 775-kilometer long and consists of five lines that are each 155-kilometers long with a transport capacity of 33.5 BCM/y. It crosses the Sicily Channel from Cap Bon to Mazara del Vallo in Sicily, the point of entry into the Italian natural gas transport system.

The GreenStream pipeline, jointly-owned with the Libyan National Oil Co, started operations in October 2004 for the import of Libyan gas produced at the Eni operated fields of Bahr Essalam and Wafa. It is 520-kilometers long with a transport capacity of 8 BCM/y crossing the Mediterranean Sea from Mellitah on the Libyan coast to Gela in Sicily, the point of entry into the Italian natural gas transport system.

Eni holds a 50% interest in the Blue Stream underwater pipeline (water depth greater than 2,150 meters) linking the Russian coast to the Turkish coast of the Black Sea. This pipeline is 774-kilometer long on two lines and has transport capacity of 16 BCM/y. It is part of a joint venture to sell gas produced in Russia on the Turkish market.

Capital expenditures

See “Item 5 – Liquidity and capital resources – Capital expenditures by segment”.

Refining & Marketing & Chemicals

Refining & Marketing

Eni’s Refining & Marketing business engages in the supply and refining of crude oil to produce a large slate of fuels and other refined products and in the marketing of fuels primarily in Italy and in selected European markets. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. The Company operations are fully integrated through refining, supply, logistics and marketing in order to maximize cost efficiencies and operational effectiveness.

The Company also engages in the production of bio-fuels at the Venice refinery, where certain renewable feedstock are processed (palm oil).

The business results depends heavily on trends in refining margins, i.e. the spread between the cost of the oil feedstock and the price of the refined products obtained from the crude processing.

In 2018 refining margins in the Mediterranean area decreased by approximately 26% y-o-y to 3.7 \$/BBL driven by the sharp increase of oil prices reported in the first ten months, not recovered in the sale prices of refining products due to competitive pressure in the markets. Management believes that refining margins will remain under pressure in the short-to-medium term due to continuing competition. In the medium-term, spreads between products and crude may find a support as a consequence of the IMO 2020 regulations, which will lead, among other solutions, to the substitution of bunker fuel oil with cleaner fuels (gasoil, ULSFO and LNG) that could be short in the first period of law application, with benefit for high conversion refineries. In the longer term, refinery margins will normalize, as a result of supply-demand re-alignment thanks investments by both refining companies (fuel oil destruction units) as well as ship-owners (scrubbers, retrofitting, new ships/engines).

The business results of operations in 2018 and its strategy are described in “Item 5 – 2016-2018 Group results of operations” and “Item 5 – Management’s expectations of operations”.

Supply

In 2018, a total of 22.62 mmtonnes of crude were purchased (compared with 24.28 mmtonnes in 2017), of which 4.14 mmtonnes by equity crude oil. The breakdown by geographic area was the following: approximately 36% of purchased crude came from the Middle East, 18% from Russia, 14% from Italy, 13% from Central Asia, 10% from North Africa, 3% from West Africa, 2% from North Sea and 4% from other areas.

Refining

In 2018, Eni refinery capacity (balanced with conversion capacity) was approximately 27.4 mmtonnes (equal to 548 KBBL/d), with a conversion index of 54%. Conversion index is a measure of refinery complexity. The higher the index, the wider the range of crude qualities and feedstock that a refinery is able to process thus enabling refineries to benefit from the cost economies arising from the discount – versus the benchmark – at which certain qualities of crude (particularly the heavy ones) may be supplied. Eni's 100% owned refineries have a balanced capacity of 19.4 mmtonnes (equal to 388 KBBL/d), with a 56% conversion index. In 2018, Eni's refineries throughputs in Italy and outside Italy were 23.23 mmtonnes. The refinery utilization rate, ratio between throughputs and refinery capacity, is 90,1%.

Refining system in 2018

	Ownership (%)	Balanced refining capacity (Eni's share) (KBBL/d)	Utilization rate (Eni's share) (%)	Conversion index[(1)] (%)	Fluid catalytic cracking (FCC)[(2)] (KBBL/d)	Residue conversion[(2)] (KBBL/d)	Hydro-cracking[(2)] (KBBL/d)	Visbreaking/ Thermal Cracking[(2)] (KBBL/d)
Wholly-owned refineries		**388**	**90**	**56**	**34**	**40**	**71**	**29**
Italy								
Sannazzaro	100	200	93	74	34	14	51	29
Taranto	100	104	73	56		26	20	
Livorno	100	84	100	11				
Partially owned refineries		**160**	**94**	**52**	**143**	**25**	**75**	**27**
Italy								
Milazzo	50	100	99	60	45	25	32	
Germany								
Vohburg/Neustadt (Bayernoil)	20	41	77	36	49			
Schwedt	8.33	19	100	42	49		43	27
Total		**548**	**91**	**54**	**177**	**65**	**146**	**56**

(1) Conversion index: catalytic cracking equivalent capacity/topping capacity (%wt).
(2) Conversion unit capacities are 100%.

Italy

Eni's refining system in Italy is composed of the wholly-owned refineries of Sannazzaro, Livorno and Taranto, as well as its 50% stake in the Milazzo refinery in Sicily. Eni's refineries operate to maximize asset value according to market conditions and the integration with marketing activities.

The Sannazzaro refinery has a balanced capacity of 200 KBBL/d and a conversion index of 74%. Located in the Po Valley, in the center of the Northern Italy, Sannazzaro is one of the most efficient refineries in Europe. The high flexibility and conversion capacity of this refinery allows it to process a wide range of feedstock. The main equipments in the refinery are: two primary distillation columns and two associated vacuum units, three desulphurization units, a fluid catalytic cracker (FCC), two hydrocrackers (HdC), two reforming units, a visbreaking thermal conversion unit integrated with a gasification producing a syngas used in a combined cycle power generation, and finally the Eni Slurry Technology (EST) plant, started up at the end of 2013. The EST plant exploits a proprietary technology to convert extra heavy crude residues (vacuum and visbreaking tar) into naphtha and middle distillates, with a conversion factor of 95%.

In January 2018 Eni has sold the licence and basic engineering project to the Chinese company Sinopec the largest refining company in the world, for the use of the EST conversion proprietary technology.

The Taranto refinery has a balanced capacity of 104 KBBL/d and a conversion index of 56%. Taranto has a strong market position due to the fact that is the only refinery in Southern Continental Italy, and is upstream integrated with the Val d'Agri fields in Basilicata (Eni 60.77%) through a pipeline. The main equipments are a topping-vacuum unit, a hydrocracking, a platforming unit and two desulphurization units.

The Livorno refinery, with a balanced refining capacity of 84 KBBL/d and a conversion index of 11%, is dedicated to the production of lubricants and specialties. The refinery is connected by pipeline to a depot in Florence (Calenzano). The refinery has a topping-vacuum unit, a platforming unit, two desulphurization units and a de-aromatization unit (DEA) – for the production of fuels; a propane de-asphalting (PDA), aromatics extraction and de-waxing units, for the production of base oils; a blending and filling plant – for the production of finished lubricants.

The Milazzo refinery (Eni 50%) has a balanced capacity of 200 KBBL/d and a conversion index of 60%. Located in Sicily, Milazzo is mainly dedicated to export and to the supply of Italian coastal depots. The main equipments in the refinery are: two primary distillation columns and a vacuum unit, two desulphurization units, a fluid catalytic cracker (FCC), one hydrocracker (HdC), one reforming unit and one LC fining (ebullated bed residue conversion).

Outside Italy

In Germany, Eni owns an interest of 8.33% stake in the Schwedt refinery (PCK) and an interest of 20% in the Vohburg and Neustadt refineries (Bayernoil). Eni's refining capacity in Germany is 60 KBBL/d to supply Eni's distribution network in the country.

Green refineries

	Ownership share (%)	**Capacity (2018)** (ktonnes/y)	**Capacity (at regime)** (ktonnes/y)	**Throughput (2018)** (ktonnes/y)
Wholly-owned				
Venezia	100	360	560	253
Gela	100		750	
Total green refineries		**360**	**1,310**	**253**

Green Refining

Eni fully owns the green refinery of Venice and the site of Gela, where another green refinery is under construction.

The Venice green refinery started production in June 2014, replacing the old oil-based refinery that was shut down. The refinery, with a production capacity of 360 ktonnes/y, leverages on the Ecofining™ proprietary technology to transform vegetable oil in hydrogenated bio-fuels. A second phase of development is underway. At full capacity, the refinery production will satisfy approximately half of Eni bio-fuels needs required for being compliant with the EU environmental normative aimed at reducing CO_2 emissions.

The Gela refinery is located in the Southern coast of Sicily. The refinery was shut-down in March 2014 and in November 2014, Eni signed a Memorandum of Understanding for the reconversion of the plant into a bio-refinery with the Italian Ministry for Economic Development and Local Authorities. In August 2017 the project obtained the environmental impact assessment and authorization (VIA/AIA) by the Italian Ministry of the Environment and the Ministry of Cultural Heritage. Upgrading works have progressed in 2018. The project is expected to come on stream in 2019. The refinery will have a capacity of 750 ktonnes/y. The conversion will leverage on the application of the Ecofining™ proprietary technology, developed and licensed by Eni, to convert unconventional and second generation raw materials into green diesel, a highly sustainable biofuel. The plant properties will allow the production of green diesel in compliance with the last regulatory constraints in terms of reduction of GHG emissions throughout the whole production chain, deploying the full capacity in process second-generation feedstock.

The table below sets forth Eni's sales of refined products by distribution channel for the periods indicated.

Availability of refined products	2018	2017	2016
		(mmtonnes)	
ITALY			
Refinery throughputs			
At wholly-owned refineries	16.78	16.03	17.37
Less input on account of third parties	(1.03)	(0.34)	(0.27)
At affiliated refineries	4.93	5.46	4.51
Refinery throughputs on own account	**20.68**	**21.15**	**21.61**
Consumption and losses	(1.38)	(1.36)	(1.53)
Products available for sale	**19.30**	**19.79**	**20.08**
Purchases of refined products and change in inventories	7.50	6.74	6.28
Products transferred to operations outside Italy	(0.54)	(0.46)	(0.39)
Consumption for power generation	(0.35)	(0.34)	(0.37)
Sales of products	**25.91**	**25.73**	**25.60**
Green refinery throughputs	**0.25**	**0.24**	**0.21**
OUTSIDE ITALY			
Refinery throughputs on own account	**2.55**	**2.87**	**2.91**
Consumption and losses	(0.20)	(0.22)	(0.22)
Products available for sale	**2.35**	**2.65**	**2.69**
Purchases of finished products and change in inventories	4.12	4.36	4.72
Products transferred from Italian operations	0.54	0.46	0.40
Sales of products	**7.01**	**7.47**	**7.81**
Refinery throughputs on own account	**23.23**	**24.02**	**24.52**
of which: refinery throughputs of equity crude on own account	*4.14*	*3.51*	*3.43*
Total sales of refined products	**32.92**	**33.20**	**33.41**
Crude oil sales	**0.28**	**0.86**	**0.20**
TOTAL SALES	**33.20**	**34.06**	**33.61**

In 2018, refining throughputs were 23.23 mmtonnes, down by 3.3% from 2017 due to the lower throughputs at the Taranto plant, reflecting higher crude oil volumes processed on behalf of third parties, at the Milazzo refinery due to maintenance standstills and at the Bayernoil refinery following an event occurred in September. These negatives were partially offset by the better performance at the Sannazzaro and Livorno refineries, with the latter affected in 2017 by a shutdown due to a force majeure event.

Outside Italy, Eni's refining throughputs were 2.55 mmtonnes, down by 320 ktonnes or 11.1% due to the above-mentioned event occurred at the Bayernoil refinery.

Total throughputs in wholly-owned refineries were 16.78 mmtonnes, up by 0.75 mmtonnes or 4.7% compared with 2017.

Approximately 18.3% of processed crude was equity, increased approximately 3.1 percentage points from 2017 (15.2%).

The volumes of biofuels produced from vegetable oil at the Venice green refinery increased by 4.2% from the corresponding period of 2017.

Logistics

Eni is a leading operator in the Italian oil and refined products storage and transportation business.

It owns an integrated infrastructure consisting of 15 directly managed depots and a network of oil and refined products pipelines. Eni logistic model is organized in three hubs (North, Central and South Italy). These hubs manage the product flows in order to guarantee high safety and technical standards, as well as cost effectiveness. Eni is also in joint venture with other Italian operators to optimize its logistic footprint and increase efficiency. Other depots are operated by seven different joint ventures (Sigemi, Petroven, Seram, Disma, Seapad, Toscopetrol and Sarroch. Eni transports oil and refined products: (i) by sea through spot and long-term contracts of tanker ships; and (ii) through a proprietary pipeline network extending approximately 1.149 kilometers in operation.

Secondary distribution to retail and wholesale markets is outsourced to independent tanker carriers, selected as market leaders in their own field.

Marketing

Eni markets a wide range of refined petroleum products, primarily in Italy, through a widespread operated network of service stations, franchises and other distribution systems.

The table below sets forth Eni's sales of refined products by distribution channel for the periods indicated.

Oil products sales in Italy and outside Italy	**2018**	**2017**	**2016**
		(mmtonnes)	
Italy			
Retail	5.91	6.01	5.93
Wholesale	7.54	7.64	8.16
	13.45	**13.65**	**14.09**
Petrochemicals	0.96	0.86	1.02
Other sales	11.5	11.22	10.49
Total	**25.91**	**25.73**	**25.60**
Outside Italy			
Retail	2.48	2.53	2.66
Wholesale	3.29	3.48	3.61
	5.77	**6.01**	**6.27**
Other sales	1.24	1.46	1.54
Total	**7.01**	**7.47**	**7.81**
TOTAL SALES	**32.92**	**33.20**	**33.41**

In 2018, sales volumes of refined products (32.92 mmtonnes) were down by 0.28 mmtonnes or by 0.8% from 2017, mainly due to the decrease of retail and wholesale sales in Italy and lower volumes marketed in the wholesalers segment in the rest of Europe.

Retail sales in Italy

In 2018, retail sales in Italy were 5.91 mmtonnes, with a slight decrease compared to 2017 (about 100 ktonnes from 2017 or 1.7%). Average gasoline and gasoil throughput (1,589 kliters) were substantially in line with 2017. Eni's retail market share of 2018 was 24%, down by 0.3 percentage points from 2017 (24.3%).

As of December 31, 2018, Eni's retail network in Italy consisted of 4,223 service stations, lower by 87 units from December 31, 2017 (4,310 service stations), resulting from the negative balance of acquisitions/releases of lease concessions (74 units), closure of low throughput stations (10 units) and the reduction in motorway concessions netted by the new opening (3 units).

Retail sales in the rest of Europe

Eni's strategy in the rest of Europe is focused on selectively growing its presence, particularly in Germany and Austria leveraging on the synergies ensured by the proximity of these markets to Eni's production and logistic facilities.

In 2018, retail sales of refined products in the rest of Europe (2.48 mmtonnes), recorded a reduction from 2017 (down by 2%). This result reflected mainly lower volumes traded in Germany due to the event occurred at Bayernoil refinery and France.

At December 31, 2018, Eni's retail network in the rest of Europe consisted of 1,225 units, decreasing by 9 units from December 31, 2017, mainly in Germany. Average throughput (2,391 kliters) decreased by 49 kliters compared to 2017 (2,440 kliters).

Other businesses

Wholesale

Eni is strongly present in wholesale market in Italy, including sales of diesel fuel for automotive use and for heating purposes, for agricultural vehicles and for vessels and sales of fuel oil. Major customers are resellers, agricultural users, manufacturing industries, public utilities and transports, as well as final users (transporters, condominiums, farmers, fishers, etc.). Eni provides its customers with its expertise in the area of fuels with a wide range of products that cover all market requirements. Customer care and product distribution are supported by a widespread commercial and logistical organization presence throughout Italy and is articulated in local marketing offices and a network of agents and concessionaires.

In 2018, sales volumes on wholesale markets in Italy (7.54 mmtonnes) were in line from the full year of 2017, mainly due to lower volumes marketed of gasoil offset by higher sales of other products.

Wholesale sales in the Rest of Europe were 2.82 mmtonnes, down by 6.9% from 2017 due to lower sold volumes in Germany and France, partly offset by higher volumes in Spain.

Supplies of feedstock to the petrochemical industry (0.96 mmtonnes) increased by 11.6%. Other sales in Italy and outside Italy (12.74 mmtonnes) slightly increased by 0.06 mmtonnes, mainly due to higher volumes sold to oil companies.

LPG

The marketing of LPG in Italy is supported by the refining production and a logistic network made up of five bottling plants, 1 owned storage site and coastal storage sites located in Livorno, Naples and Ravenna.

LPG is used as heating and automotive fuel. In 2018, Eni share of LPG market in Italy was 17.8%.

Outside Italy, the main market of Eni is Ecuador, with a market share of 37.3%.

Lubricants

Eni operates six (owned and co-owned) blending and filling plants, in Italy, Spain, Germany, USA, Africa and in the Far East. With a wide range of products composed of over 650 different blends Eni masters international state of the art know how for the formulation of products for vehicles (engine oil, special fluids and transmission oils) and industries (lubricants for hydraulic systems, industrial machinery and metal processing). In Italy, Eni is leader in the manufacture and sale of lubricant bases, manufactured at Eni's refinery in Livorno. Eni also owns one facility for the production of additives in Robassomero.

In 2018, Eni's share of lubricants market in Italy was 19.06%, in Europe 3% and on a worldwide base 1%. Eni operates in more than 80 countries by subsidiaries, licensees and distributors.

Oxygenates

Eni's, through its subsidiary Ecofuel (100% Eni's share), sells approximately 0.9 mmtonnes/y of oxygenates, mainly ethers (approximately 3% of world demand, used as a gasoline octane booster) and methanol (mainly for petrochemical use). About 79% of oxygenates are produced in Eni's plants in Italy (Ravenna), Saudi Arabia (in joint venture with Sabic) and Venezuela (in joint venture with Pequiven) and the remaining 21% is purchased.

Chemicals

Eni operates in the businesses of olefins and aromatics, basic and intermediate products, polystyrene, elastomers and polyethylene. Its major production hubs are located in Italy and Western Europe. At the end of 2017 Eni started operations for the production of elastomers in South Korea in joint venture with a local operator.

The business results of operations in 2018 and its strategy are described in "Item 5 – 2016-2018 Group results of operations" and "Item 5 – Management's expectations of operations".

In 2018 sales of chemical products amounted to 4,938 ktonnes, increased from 2017 (up by 292 ktonnes, or 6.3%). The main increases were registered in olefins (up by 14.8%) and derivatives (up by 20.4%), partly offset by lower sales volumes of polyethylene (down by 6.3%) and elastomers (down by 3.2%).

Average unit sales prices of the intermediates business increased by 7.1% from 2017, with olefins and aromatics up by 10.9% and 4,2%, respectively. Despite, the polymers reported a decrease of 2.4% from 2017.

Petrochemical production of 9,483 ktonnes increased by 528 ktonnes (up by 5.9%) mainly due to higher production of intermediates business (up by 8.1%), in particular derivatives up by 17.6%; the polymers productions were substantially in line despite the improvement of styrenics (+8.3%).

The main increases in production were registered at the Porto Marghera site (up by 22.9%), due to a recovery of production capacity for a shutdown in 2017, as well as Szàshalombatta, Mantova and Priolo sites. Decreasing productions at the Ferrara, Brindisi and Oberhausen sites due to unplanned shutdowns of the plants in 2018.

Nominal capacity of plants is in line from the previous year. The average plant utilization rate calculated on nominal capacity was 76.2% increased from 2017 (72.8%).

The table below sets forth Eni's main chemical products availability for the periods indicated.

	Year ended December 31,		
	2018	**2017**	**2016**
		(ktonnes)	
Intermediates	7,130	6,595	6,580
Polymers	2,353	2,360	2,229
Total production	**9,483**	**8,955**	**8,809**
Consumption and losses	(5,085)	(4,566)	(4,917)
Purchases and change in inventories	540	257	853
	4,938	**4,646**	**4,745**

The table below sets forth Eni's main petrochemical products revenues for the periods indicated.

	Year ended December 31,		
	2018	**2017**	**2016**
		(€ million)	
Intermediates	2,401	1,988	1,688
Polymers	2,589	2,730	2,380
Other revenues	130	133	128
Total revenues	**5,120**	**4,851**	**4,196**

Intermediates

Intermediates revenues (€2,401 million) increased by €413 million from 2017 (up by 20.8%) reflecting the higher commodity prices scenario that influences average intermediates prices of the main product of the business unit. Sales increased by 12.3%, in particular for ethylene business (up by 30.3%) and derivatives (up by 20.4%) driven by higher availability of product following the shutdowns in 2017.

Average unit prices increased by 7.1%, in particular olefins (up by 10.9%) and aromatics (up by 4.1%); decreasing of derivatives (down by 9.3%).

Intermediates production (7,130 ktonnes) registered an increase of 8.1% from the last year. Increasing of derivatives (up by 17.6%), aromatics (up by 8.3%) and olefins (up by 7%).

Polymers

Polymers revenues (€2,589 million) decreased by €141 million or 5.2% from 2017 due to lower sales volumes (down by 2.5%), as well as to the decrease of the average unit prices (down by 2.4%).

The styrenics business benefitted from the high sold volumes (up by 5.8%) for higher product availability; slightly decrease of sold prices (down by 1.4%).

Polyethylene volumes decreased (down by 6.4%) due to oversupply and mounting competitive pressure from cheaper products streams from the Middle-East and the USA; decreasing of average prices (down by 3.9%).

Polymers productions are in line from 2017 (2,353 ktonnes) despite the lower productions of polyethylene (down by 7.3%) and elastomers (down by 2.7%). The styrenics business reported higher production of styrene (up by 12.1%) and HIPS (up by 11.7%).

Versalis also engages in the production of chemicals from renewables sources through a 50%-owned joint venture with Novamont for the production of chemicals from crop and the acquisition in 2018 of the segment of green chemicals of the Mossi & Ghisolfi Group. In particular, the new assets will allow the valorization of biomass and the re-launch of the international licensing of a proprietary technology to produce second generation bio-ethanol, to meet the growing demand and sustainability criteria required for bio-fuels.

Capital expenditures

See "Item 5 – Liquidity and capital resources – Capital expenditures by segment".

Corporate and Other activities

These activities include the following businesses:

- the "Other activities" segment comprises results of operations of Eni's subsidiary Syndial which runs reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or shut down in past years, as well as Eni New Energy SpA which engages in developing the business of renewable energy; and
- the "Corporate and financial companies" segment comprises results of operations of Eni's headquarters and certain Eni subsidiaries engaged in treasury, finance and other general and business support services. Eni's headquarters is a department of the parent company Eni SpA and performs Group strategic planning, human resources management, finance, administration, information technology, legal affairs, international affairs and corporate research and development functions. Through Eni's subsidiaries Eni Finance International SA, Banque Eni SA, Eni International BV, Eni Finance USA Inc and Eni Insurance DAC, Eni carries out cash management activities, administrative services to its foreign subsidiaries, lending, factoring, leasing, financing Eni's projects around the world and insurance activities, principally on an intercompany basis. EniServizi, Eni Corporate University, AGI and other minor subsidiaries are engaged in providing Group companies with diversified services (mainly services including training, business support, real estate and general purposes services to Group companies). Management does not consider Eni's activities in these areas to be material to its overall operations.

Seasonality

Eni's results of operations reflect the seasonality in demand for natural gas and certain refined products used in residential space heating, the demand for which is typically highest in the first quarter of the year, which includes the coldest months and lowest in the third quarter, which includes the warmest months. Moreover, year-to-year comparability of results of operations is affected by weather conditions affecting demand for gas and other refined products in residential space heating. In colder years, which are characterized by lower temperatures than historical average temperatures, demand for gas and products is typically higher than normal consumption patterns, and vice versa.

Research and development

Research and development is a key element in Eni's transformation into an integrated energy company in a low-carbon future. The availability and development of cutting-edge technological skills at the service of innovation and sustainability and the continuous commitment to multiply the areas of application of the energy solutions identified are the common denominator of our activities.

Research projects cover every aspect of our value chain, with the aim of reducing risks and increasing efficiency, consolidating technological leadership and, in general, achieving greater quality, efficiency and sustainability in products, plants and processes.

Research and Development becomes, therefore, the lever to create value, with the aim of minimizing the time to market that from research leads to the development of technologies and their implementation on an industrial scale.

In 2018, Eni filed 43 patent applications (27 in 2017).

In 2018, Eni's overall expenditure in R&D amounted to €197 million which were almost entirely expensed as incurred (€185 million in 2017 and €161 million in 2016).

Exploration & Production

Proprietary software for seismic signal processing, petroleum system modeling and flow assurance that confirms and strengthens Eni's position at the top of the industry, both in terms of operating results and with significant savings on the cost of licenses and code maintenance.

Drilling automation. Two new tools addressing lost/non productive time and based on big data technology were developed in 2017 to support operations. The first tool is e.NPT (Eni Non Productive Time) which analyzes and integrates multiple data sources in real time in order to predict sticking events. The second tool is a new solution enabling a near real time performance analysis to identify Invisible Lost Times.

Drilling Safety Technologies: to reduce by two orders of magnitude the risk of blowout occurrence compared to the OGP reference. To achieve this goal, new technologies able to improve well integrity both during drilling and well productive life are being developed.

Eni Subsea Hub Technology Solutions: to develop, together with industry partners, technologies to significantly reduce subsea development CAPEX and OPEX by using full subsea architectures, very long step-outs and life-of-field robotics. The program starts from lessons learned from Eni's most recent subsea development projects (started-up in the last 3 years). The objective is to increase the distance between new subsea production systems and existing floating production facilities, or connect those new subsea assets directly to shore. Cost effective and flexible extra-long subsea architectures prove to efficiently work on a wide range of applications and design basis parameters. Key enabling technologies under development are multicontrol communication, subsea power distribution, subsea boosting and thermal management.

Refining & Marketing and Petrochemicals

Methanol based alternative fuels. A new gasoline formulation containing alternative fuels (15% methanol and 5% bioethanol comprising a proper additive package to protect the engine), labeled M15, has been developed and is currently undergoing extensive road tests on five Fiat 500 cars belonging to the car sharing Enjoy fleet in Milan. M15 can provide more than 3% CO_2 tailpipe emissions reduction due to the lower H/C ration and higher octane number.

i-Sigma Bio Tech lubricants. Eni R&D in collaboration with Versalis and Matrìca developed a new synthetic lubricant base stock of ester type, obtained from renewable sources. This synthetic product is featured with excellent properties in terms of oxidation stability, volatility and wear protection that are suitable for several applications in the industrial and automotive lubrication sectors. Bioester is a key component of a new SAE 10W-30 engine oil for heavy duty services (trucks, buses, and off-road vehicles) designed and tested by Eni to meet some important international technical specifications, and ready for the market under the brand name i-Sigma Bio Tech.

Energy Saving Lubricants: In collaboration with BHGE, Eni has developed an innovative low viscosity oil for turbomachinery sector, Eni OTE GT 15, that showed outstanding energy saving characteristics by reducing friction losses up to 15%, decreasing the consumption of natural gas and decreasing CO_2 emissions.

Guayule. Project aiming at the production of natural latex, dry rubber and resins from Guayule (ongoing experimental cultivation in Basilicata and Sicily) with exploitation of all components with proprietary technologies and their development in the market allowing the use of whole value of the Guayule plant.

An important agreement has been signed with one of the most important international player in the field of tire manufacturing for the joint development of a common technology platform for guayule production and applications.

Bio-butadiene. A joint venture between Versalis and Genomatica has developed a process to produce 1,3 bio-butadiene from renewable sources via sugars production from biomasses, fermentation and subsequent chemical processes.

Renewable Energy & Environment

Concentrated Solar Power. The Eni R&D effort towards the definition and application of improved Concentrated Solar Power (CSP) solutions has led to proprietary technology assemblies with advantageous capital investment and operation costs. A long-term partnership with Massachusetts Institute of Technology and the Politecnico of Milano (that has realized the first proprietary CSP prototype) has allowed the focusing of capabilities for this purpose. The deployment phase is ongoing in the South of Italy, with a pilot plant in Gela (Sicily) and a demo plant of 1MW thermal power.

Organic Photovoltaic. New solutions (active and buffer materials) for flexible solar cells have been developed and applied in an emerging field that relies on organic polymeric photovoltaic solutions. The developed technology solutions allow easy transportation and application wherever power is required and no grid infrastructure is available. Thanks to the light weight and the technical and operational simplicity some photovoltaic modules with inflatable support have been also developed and installed in demonstrative situations.

Energy storage. The storage of the electric energy produced from renewable sources is indeed a key issue for allowing the further development of this field. Accordingly, Eni is testing solutions for Redox Flow Batteries and for integrating these devices "conventional" electrical energy production devices such as gas turbines and diesel generators in demonstrative plants for off-grid applications. Targeting in these cases a relevant CO_2 (higher that 75%) emission reduction.

Phytoremediation. Field tests showed that selected Plant Growth-Promoting Rhizobacteria able to enhance the plants biomass, increasing the uptake of metallic soil contaminants. The usage of these bacteria has been experimented in field tests for promoting the biodegradation of hydrocarbons in polluted environments (Ravenna, Priolo and Mantova).

Hydrocarbon recovery. Eni developed and applied a proprietary technology (e-hyrec®) allowing the remediation of aquifer environments through the recovery and separation of hydrocarbon contaminants. The full commercialization phase will begin in the second quarter of 2018.

Soil and Groundwater Bioremediation: Eni R&D has developed through laboratory, pilot and field scale tests, technologies and site-specific protocols (e-lamina®) for treating contaminated soils and groundwater utilizing biological, environmental-friendly and cost-effective means. The protocols involve: (i) sampling and site characterization, (ii) evaluation of the bio-degradation potential by micro/meso-cosm test studies, (iii) in situ pilot plant activities, (iv) design and application of full-scale bio-remediation treatments.

Waste to Fuel. Eni is evaluating a Waste-to-Fuel process able to transform wet domestic waste into bio-oils suitable to feed Eni's biorefineries to obtain second-generation biofuels. A pilot has been developed in Gela and it started the operations at the end of 2018.

Energy Transition

Eni launched the "Energy Transition" R&D program with the aim of developing new technologies to promote the widespread use of natural gas, making easier its production and transport, widening its uses and favoring the decarbonization of the whole value chain. In particular, the research deals with three areas of interest:

a) Natural gas transportation, transformation and uses,

b) H_2S management,

c) CO_2 management.

On the forefront of Natural Gas transportation and conversion, important results have been obtained for the development of a process for the production of methanol from natural gas. The process is based on an Eni proprietary technology for the conversion of methane to syngas, which is cheaper and has a footprint and a weight much lower than the existing processes based on steam reformer.

In the area of H_2S and CO_2 capture, innovative highly effective solvents for the separation of H_2S and CO_2 from natural gas have been identified and tested at lab scale. Now the results is under scaling-up to a pilot unit with the cooperation of an external specialized company. New ways for sulphur utilization are under consideration. Innovative sulphur-based products which can be used in agriculture have been obtained and are under testing in a field parcel in Central Italy.

Insurance

In order to control the insurance costs incurred by each of Eni's business units, the Company constantly assesses its risk exposure in both Italian and foreign activities. The Company has established a captive subsidiary, Eni Insurance DAC, in order to efficiently manage transactions with mutual entities and third parties providing insurance policies. Internal insurance risk managers work in close contact with business units in order to assess potential underlying business and other types of risks and possible financial impacts on the Group results of operations and liquidity. This process allows Eni to accept risks in consideration of results of technical and risk mitigation standards and practices, to define the appropriate level of risk retention and, finally, the amount of risk to be transferred to the market. Eni enters into insurance arrangements through its shareholding in the Oil Insurance Ltd (OIL) and with other insurance partners in order to limit possible economic impacts associated with damages to both third parties and the environment occurring in case of both onshore and offshore accidents. The main part of this insurance portfolio is related to operating risks associated with oil&gas operations which are insured making use of insurance policies provided by the OIL, a mutual insurance and re-insurance company that provides its members with a broad coverage of insurance services tailored to the specific requirements of oil and energy companies. In addition, Eni uses insurance companies who it believes are established in the marketplace. Insured liabilities vary depending on the nature and type of circumstances; however, underlying amounts represent significant shares of the plafond granted by insuring companies. In particular, in the case of oil spills and other environmental damage, current insurance policies cover costs of cleaning-up and remediating polluted sites, damage to third parties and containment of physical damage up to $1.2 billion for offshore events and $1.4 billion for onshore plants (refineries). These are complemented by insurance policies that cover owners, operators and renters of vessels with the following maximum amounts: $1,250 million for the fleet owned by the subsidiary LNG Shipping in the Gas & Power segment and time charters; $1 billion for FPSOs used by the Exploration & Production segment for developing offshore fields.

Management believes that the level of insurance maintained by Eni is generally appropriate for the risks of its businesses. However, considering the limited capacity of the insurance market, we believe that Eni could be exposed to material uninsured losses in case of catastrophic incidents, like the one occurred in the Gulf of Mexico in 2010 which could have a material impact on our results, liquidity prospects, share price and reputation. See "Item 3 – Risk factors – Risk associated with the exploration and production of oil and natural gas".

Environmental matters

Environmental regulation

Eni is subject to numerous EU, international, national, regional and local environmental, health and safety laws and regulations concerning its oil&gas operations, products and other activities, including legislation that implements international conventions or protocols. In particular, exploration, drilling and production activities require acquisition of a special permit that restricts the types, quantities and concentration of various substances that can be released into the environment. The particular laws and regulations can also limit or prohibit drilling activities in the certain protected areas or provide special measures to be adopted to protect health and safety at workplace and health of communities that could have been affected by the Company's activities. These laws and regulations may also restrict emissions and discharges to surface and subsurface water resulting from the operation of natural gas processing plants, petrochemical plants, refineries, pipeline systems and other facilities that Eni owns. In addition, Eni's operations are subject to laws and regulations relating to the production, handling, transportation, storage, disposal and treatment of waste materials. Environmental laws and regulations have a substantial impact on Eni's operations. Some risk of environmental costs and liabilities is inherent in certain operations and products of Eni, and there can be no assurance that material costs and liabilities will not be incurred. See "Item 3 – Risk factors".

We believe that the Company will continue to incur significant amounts of expenses in order to comply with pending environmental, health and safety protection and safeguard regulations, particularly in order to achieve any mandatory or voluntary reduction in the emission of GHG in the atmosphere and cope with climate change and water quality of discharges, as well as availability.

European Union Environmental Laws Framework

In 2018, the main environmental efforts of the European Union continued to focus on the air quality, energy transition, circular economy, clean mobility, energy efficiency and climate change.

On November 4, 2016, the Paris Agreement entered into force, exactly 30 days after the date on which the last of at least 55 Parties to the Convention accounting in total for at least an estimated 55% of the total global greenhouse gas emissions have deposited their instruments of ratification. To date, the 185 Parties have ratified the Convention. This important step in the common international Climate Change strategy sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C. By the ratification of the Convention, the governments agreed to limit the increase to 1.5°C, since this would significantly reduce risks and the impacts of climate change. In 2018, the UN Climate Change Conference (COP 24) had taken place in Katowice (Poland). The COP 24 was the next step for governments to implement the Paris Agreement "rulebook" and accelerate the transformation to sustainable, resilient and climate-safe development. This conference further clarified the enabling frameworks that will make the agreement fully operational and the support needed for all nations to achieve their climate change goals. The participated countries had continued to negotiate the finer details of how the agreement will work from 2020 onwards. In particular, the final Decision of the COP24 defined the guidelines for most of the major mechanisms introduced by the Paris Agreement, such as the financial support for developing countries, the preparation and communication of the Parties emission reduction commitments, the periodic review of the results and the transparency of the information. However, the COP24 did not make any progress on the rules for the carbon offsets development and emission trading between Parties and privates (article 6 of the Paris Agreement). On this topic, the negotiations could not go over the impasse due to a divergence between the Parties on a few crucial points.

On October 4, 2016, the European Parliament approved the ratification of the Paris Agreement by the European Union. The Paris Convention vindicates the EU strategy in climate change defined in October 2014, when the European Council agreed on the 2030 climate and energy policy framework. In this strategy the EU stated an ambitious economy-wide domestic target of at least 40% GHG reduction for the period up to 2030 (below 1990 levels) and to a 27% share of renewable energy in final energy consumption.

On November 30, 2016, the following step of this strategy was written down, when the EU Commission presented the Clean Energy for All Europeans (so called "Clean Energy Package"). By this proposal, the EU is consolidating the enabling environment for the transition to a low carbon economy through a wide range of interacting policies and instruments reflected under the Energy Union Strategy. The Package has three main goals: putting energy efficiency first, achieving global leadership in renewable energies and providing a fair deal for consumers. The Package includes the revision of the Directive 2012/27/EU on Energy Efficiency (EED) with the goal to adapt the existing Directive in order to meet EU climate and energy targets for 2030 and align it with other aspects of the Clean Energy package, including a revised Energy Performance of Buildings Directive (EPBD), a recast directive on the Promotion of Renewable Energy Sources – Directive 2009/28/CE (RED II) and a new regulation on Governance of Energy Union.

Negotiations have now been concluded on all aspects of the new Clean Energy Package and all of the new rules will be formally adopted in the 2019. Finalising these changes will mark a significant step towards the creation of the Energy Union and delivering on the EU's Paris Agreement commitments. The new legislative package strengthens two existing targets for the EU by 2030: a binding renewable energy target of at least 32% and an energy efficiency target of at least 32.5% – with a possible upward revision in 2023. For the electricity market, it confirms the 2030 interconnection target of 15%, following on from the 10% target for 2020. These policies will lead to steeper emission reductions for the whole EU than anticipated – some 45% by 2030 relative to 1990 (compared to the existing target of a 40% reduction). The revised Renewable Energy Directive sets also the target for renewable energy in the transport sector. In particular, Member States must require fuel suppliers to supply a minimum of 14% of the energy consumed in road and rail transport by 2030 as renewable energy. Within the target, the advanced biofuels must be supplied at a minimum of 0.2% of transport energy in 2022, 1% in 2025 and increasing to at least 3.5% by 2030. On the other hand, biofuels produced from food and feed crops will be frozen at 2020 consumption levels plus an additional 1% with a maximum cap of 7% of road and rail transport fuel in each Member State. Lastly, biofuels produced from used cooking oil and animal fats will be capped at 1.7% in 2030, even if Member States may, where justified, modify that limit, taking into account the availability of feedstock. In terms of environmental sustainability, the European Commission set out limits and sustainable criteria on high Indirect Land Use Change-risk feedstocks, such as palm oil. These feedstocks will be capped at 2019 levels until 2023. After that, they will be progressively phased-out up to zero percent by 2030.

The Clean Energy Package also sets up a robust governance system for the Energy Union and each Member State is now required to draft integrated national energy and climate plans for 2021 to 2030 outlining how they will achieve their respective targets. A further part of the package seeks to establish a modern design for the EU electricity market, adapted to the new realities of the more flexible market, better placed to integrate a greater share of renewables.

The Clean Energy Package targets also played an important part in the Commission's preparation for its long-term vision for a climate neutral Europe by 2050, published on 28 November 2018, before the COP24. The 2050 strategy shows how Europe can lead the way to climate neutrality by investing into realistic technological solutions, empowering citizens and aligning action in key areas such as industrial policy, finance or research – while ensuring social fairness for a just transition. The 2050 strategy will be firstly debated at the European Council on May 9, 2019 in Sibiu and then adopted by the European Council in the second half of 2020.

Under the electricity market reform, a Directive and a Regulation, the European Commission introduced a new limit for power plants eligible to receive subsidies as capacity mechanisms. Subsidies to generation capacity emitting 550gr CO_2/kWh or more will be phased out, as of 2020 for new infrastructure and as of 2025 for existing plants. The Commission's proposal has been approved and emerges as one the main points of the EU climate legislation. The 550gr criterion, used in the European Investment Bank's policy, is technology neutral and in practice preclude from the subsidies the coal power plants and some inefficient gas plants.

A centerpiece of the EU's 2030 energy and climate policy framework is the binding target to reduce overall GHG emissions by at least 40% below 1990 levels by 2030. To achieve this cost-effectively, the sectors covered by the EU Emission Trading System (EU ETS) will have to reduce their emissions by 43% compared with 2005, while non-ETS sectors will have to reduce theirs by 30%. The ETS is now in the last years of the III phase (2013 – 2020). In July 2015, the European Commission published its proposal to revise the directive on the EU ETS for the 2021 – 2030 period (Phase IV) and on February 2018, the European Council formally approved the reform of the EU ETS for phase IV to ensure the energy sector and energy intensive industries deliver the emissions reductions needed. To this end, the overall number of emission allowances will decline at an annual rate of 2.2% from 2021 onwards, compared to 1.74%. The new list of carbon leakage sectors has also been published and includes all the Eni's activity sectors excluding the extraction and production of natural gas. The carbon leakage sectors will receive 100% of the free allowances calculated with the sectorial benchmark, for all the IV phase (2021 – 2030). Currently around 46% of Eni's direct GHG emissions are included within the Carbon Pricing Scheme by its participation in the EU ETS.

In May 2018, the European institutions adopted the Effort Sharing Regulation (ESR) to ensure further emission reductions in sectors falling outside the scope of the EU emissions trading system (ETS) for the period 2021 – 2030. The ESR maintains existing flexibilities (e.g. banking, borrowing and buying and selling between Member States) and provides two new flexibilities, allowing the use of some EU ETS emissions allowances and credits from land use sector to achieve the final target. This agreement brings the EU closer to fulfilling its Paris climate commitment of an at least 40% cut in greenhouse gas emissions by 2030 compared to 1990 levels. The regulation aims to ensure that the non-ETS sectors emissions reduction target of 30% by 2030 compared to 2005 levels is reached in the effort sharing sectors, including buildings, agriculture (non-CO_2 emissions), waste management and transport (excluding aviation and international shipping).

Air quality remains at the center of the European environmental policies and strategies. On December 18, 2013, the European Commission adopted a package of proposals to improve air quality in the EU, which updated the air policy objectives for 2020 and 2030. The package includes a long-awaited revision of the National Emission Ceilings (NEC) Directive, a proposal to address emissions from medium scale combustion plants (MCP) and a proposal for ratification of the recently amended Gothenburg Protocol.

In order to guarantee better quality standards and to shift toward a low carbon economy, in December 2017, the Commission has launched the Clean Mobility Package. This is a decisive step forward in implementing the EU's commitments under the Paris Agreement for a binding domestic CO_2 reduction of at least 40% till 2030. Its aim is to help accelerate the transition to low- and zero emissions vehicles, through a new target for the EU fleet wide average CO_2 emissions of new passenger cars and vans of 30% by 2030 to provide stability and long-term direction. The Mobility Package has a 2025 intermediary target of 15% to ensure that investments kick-start already now. As the confirmation of Eni's involvement in sustainable mobility in November Eni and FCA have signed a contract to carry out research and develop technological applications aimed at reducing CO_2 emissions in road transport.

On December 31, 2016, the new National Emissions Ceilings (NEC) Directive entered into force. The NEC directive based on a Commission proposal sets stricter limits on the five main pollutants in Europe: sulfur dioxide (SO2), nitrogen oxides (NOx), ammonia (NH3), volatile organic compounds (VOC) and primary particulate matter (PM). The NEC Directive must be transposed by the Member states by June 30, 2018. The new NEC directive repeals and replaces Directive 2001/81/EC. Each EU Member State is required to produce a National Air Pollution Control Program by March 31, 2019 setting out the measures it will take to ensure compliance with the 2020 and 2030 reduction commitments.

On December 18, 2015, the Directive No. 2015/2193/EU on the limitation of emissions of certain pollutants into the air from medium combustion plants entered into force. The Medium Combustion PlanT Directive (MCP Directive) regulates pollutant emissions from the combustion of fuels in plants with a rated thermal input equal to or greater than 1 MW and less than 50 MW. The MCP Directive is a part of the Clean Air Policy Package adopted on December 18, 2013 and it regulates emissions of SO_2, NOX and dust into the air with the aim of reducing those emissions and the risks to human health and the environment they may cause. The MCP Directive will have to be transposed by Member States by December 19, 2017. The MCP Directive also ensures implementation of the obligations arising from the Gothenburg Protocol under the UNECE Convention on Long-Range Trans-boundary Air Pollution.

The Industrial Emission Directive (IED) 2010/75/EU is fundamental for European industries, it provides the framework for granting permits for about 50,000 industrial installations across the EU. It lays down rules on the integrated prevention and control of air, water and soil pollution arising from industrial activities. As part of the IED framework, additional emission limit values are defined by the sector specific and cross-sector Best Available Technology (BAT) Conclusions.

In 2016, the Commission has published the Implementing Decision (EU) 2016/902 of 30 May 2016 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU, for common wastewater and waste gas treatment/management systems in the chemical sector.

In August 2017 the Commission Implementing decision 2017/1442 of July 31, 2017 entered in force. The decision establishes the best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants (LCP – combustion installations with a rated thermal input exceeding 50 MW). Plants with a thermal input lower than 50 MW are, however, discussed in the LCP BAT where technically relevant because smaller units can potentially be added to a plant to build one larger installation exceeding 50 MW. In December 2017, the Large Combustion Plant Best Available Technique reference document (LCP BREF) was published. The update of both documents was expected under the Emission Directive and will have a significant implication on the Eni's technologies applied in the power plants. A Technical Working Group has been formed to implement a new Best Available Techniques Guidance Document on the upstream hydrocarbon exploration and production sector. Moreover, in November, Commission has published its implementing decision establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for the production of large volume organic chemicals (LVOC BAT). New emissions and efficiency standards will help national authorities to lower the environmental impact of the 3,200 installations that produce Large Volume Organic Chemicals (LVOC) and represent 63% of the EU's entire chemical industry.

In 2017 (at the latest on May 16) all Member States must apply the rules of the new Environmental Impact Assessment Directive 2014/52/EU (EIA). The EIA Directive should simplify the rules for assessing the potential effects of projects on the environment and boarders scope of the EIA covering new issues such as climate change, biodiversity, resource efficiency and risks prevention on both human and environmental aspects.

Fluorinated gases ('F-gases') play an important role in the accomplishment of the Paris Agreement and in the EU environmental policy. These ozone-depleting substances are regulated by F-gas Regulation (No. 517/2014) which applies from January 1, 2015. The new regulation strengthens the previous measures and should cut by 2030 the EU's F-gas emissions by two-thirds compared with 2014 levels. This represents a fair and cost-efficient contribution by the F-gas sector to the EU's objective of cutting its overall GHG emissions by 80 – 95% of 1990 levels by 2050. In 2017, the EU continued to shape the F-gases strategy. In October 2017, the Commission Implementing Decision (EU) 2017/1984 was published in the Official Journal. The decision sets a reference values for the period January 1, 2018 to December 31, 2020 for each producer or importer which has lawfully placed on the market hydrofluorocarbons from January 1, 2015 UE of October 24, 2017.

Moreover, in October 2016 the Kigali amendment to the Montreal Protocol (on Substances that Deplete the Ozone Layer) was signed in Rwanda. In July 2017, the EU formally ratified the Kigali Amendment to the Montreal Protocol, which aims to gradually reduce global production and consumption of hydrofluorocarbons (HFCs). Implementation of the agreement is expected to prevent up to 80 billion tonnes CO_2 equivalent of emissions by 2050, which will make a significant contribution to the Paris Agreement. The EU member states, like other developed countries, are required to start the first reductions in 2019.

During the reporting year, the EU focused on improving the environmental management principles and rule. In December, the Commission published the decision, amending the user's guide setting out the steps needed to participate in EMAS (decision 2017/2285). The guidelines offer an additional information and guidance about the steps needed to participate in EMAS, which represents the voluntary participation by organizations in a Community eco-management, and audit scheme. In November, Commission Guidelines on Environmental Impact Assessment (EIA) were released (they include three parts: Guidance Document on Screening, Guidance Document on Scoping and Guidance Document on the preparation of the EIA Report). The Commission has updated and revised the 2001 EIA Guidance Documents to reflect both the legislative changes brought by 2014/52/EU and the current state of good practice. In February 2018, the working group of experts has started the revision of the ISO 14067 standard that specifies principles, requirements and guidelines for the quantification and communication of the carbon footprint of a product (CFP), based on International Standards on life cycle assessment.

In 2015 the European Commission adopted the Circular Economy Package, which includes revised legislative proposals on waste to stimulate Europe's transition towards a circular economy which emphasizes the need to move towards a lifecycle-driven 'circular' economy, with a cascading use of resources and residual waste that is close to zero. As part of a shift in EU policy towards a circular economy, the European Commission made four legislative proposals introducing new waste-management targets regarding reuse, recycling and landfilling. The proposals also strengthen provisions on waste prevention and extended producer responsibility, and streamline definitions, reporting obligations and calculation methods for targets. In 2017, the consensus on the Circular Economy has grown significantly in EU. In December 2017, the negotiators from the European Parliament and EU member states reached an agreement and the circular economy package should be approved in the second quarter of 2018, by both the European parliament and Member States. In January 2018, the first Europe-wide strategy on plastics was adopted. By 2030, all plastics packaging should be recyclable. The strategy also highlights the need for specific measures, possibly a legislative instrument, to reduce the impact of single-use plastics, particularly in the seas and oceans. The O&G sector will have to put a significant effort to follow the "circular philosophy" by investing in innovative technological solutions, optimization of the water use, energy efficiency and the green procurement.

European Union Health and Safety Laws Framework

Legislative Decree No. 81/2008 concerned the protection of health and safety in the workplace and was designed to regulate the work environments, equipment and individual protection devices, physical agents (noise, mechanical vibrations, electromagnetic fields, optical radiations, etc.), dangerous substances (chemical agents, carcinogenic substances, etc.), biological agents and explosive atmosphere, the system of signs, video terminals. Eni worked on the implementation of the general framework regulations on health and safety concerning prevention and protection of workers at national and European level to be applied to all kinds of workers and employees.

On June 1, 2007, the REACH Regulation of the European Union (EC No. 1907/2006 of December 18, 2006) entered into force. REACH stands for Registration, Evaluation, Authorization and Restriction of Chemicals and was adopted to improve the protection of human health, safety and the environment from the risks that can be posed and caused by chemicals, while enhancing the competitiveness of the EU chemical industry. It also promotes alternative methods for the assessment of hazardous substances in order to reduce the number of tests on animals. REACH places the burden of proof on companies. To comply with the regulation, companies must identify and manage the risks linked to the substances they manufacture and market in the EU. They have to demonstrate to the European Chemicals Agency (ECHA) how the substance can be safely used and communicate risk management measures to users. If the risks cannot be managed, Authorities can restrict the use of substances in different ways. Over time, hazardous substances should be substituted with less dangerous ones. The deadline of the REACH registration depends on the tonnage band of a substance and the classification of a substance; next and last deadline is 2018. Eni recognizes the importance of the Regulation EC No. 1907/2006 (REACH), the general principles of which are already an intrinsic part of the Company's commitment to sustainability and are an integral part of the culture and history of the Company. The compliance with the REACH requirements and the involvement of all the interested parties in the Company are coordinated and supervised by the HSEQ function. In particular, Eni is involved in the registration of substances to ECHA which regards a complex series of information about the characteristics of such substances and their uses and in another fundamental aspect that concerns the exchange of information between producers and importers, as well as the users of chemical substances ("downstream users").

The CLP Regulation (Classification, Labeling and Packaging) entered into force in January 2009 (Regulation EC No. 1272/2008 on the classification, labeling and packaging of substances and mixtures), and the method of classifying and labeling chemicals introduced is based on the United Nations' Globally Harmonized System. The Regulation will replace two previous pieces of legislation, the Dangerous Substances Directive and the Dangerous Preparations Directive. The CLP Regulation ensures that the hazards presented by chemicals are clearly communicated to workers and consumers in the European Union through classification and labeling of chemicals. Before placing chemicals on the market, the industry must establish the potential risks to human health and the environment of such substances and mixtures, classifying them in line with the identified hazards. The hazardous chemicals also have to be labeled according to a standardized system so that workers and consumers know about their effects before they handle them.

European institutions have also increased their activities in the area of environmental protection in the field of hydrocarbon extraction.

On June 12, 2013, the Directive No. 2013/30/EU was issued with the aim of replacing the existing National Legislations and uniform the legislative approach at European level. The main elements of the EU Directive are the following:

- The Directive introduces licensing rules for the effective prevention of and response to a major accident. The licensing authority in Member States will have to make sure that only operators with proven technical and financial capacities are allowed to explore and produce oil&gas in EU waters. Public participation is expected before exploratory drilling starts in previously un-drilled areas.
- Independent national competent authorities, responsible for the safety of installations, are in charge of verifying the provisions for safety, environmental protection, and emergency preparedness of rigs and platforms and the operations conducted on them. Enforcement actions and penalties apply in case of non-compliance with the minimum set standards.
- Obligatory emergency planning calls for companies to prepare reports on major hazards, containing an individual risk assessment and risk-control measures, and an emergency response plan before exploration or production begins. These plans have to be submitted to National Authorities.
- Technical solutions presented by the operator need to be verified independently prior to and periodically after the installation is taken into operation.
- Companies are required publish on their websites information about standards of performance of the industry and the activities of the national competent authorities, as well as reports of offshore incidents.
- Companies are required prepare emergency response plans based on their rig or platform risk assessments and keep resources at hand to be able to put them into operation when necessary. These plans are periodically tested by the industry and National Authorities.
- Oil and gas companies are fully liable for environmental damage caused to the protected marine species and natural habitats. For damage to waters, the geographical zone is extended to cover all EU waters including the exclusive economic zone (about 370 km from the coast) and the continental shelf, where the coastal Member States exercise jurisdiction. For water damage, the present EU legal framework for environmental liability is restricted to territorial waters (about 22 km offshore).
- Operators working in the EU are required to demonstrate they apply the same accident-prevention policies overseas as they apply in their EU operations.

We believe that Eni operations are currently in compliance with all those regulations in each European country where they have been enacted.

Adoption of stricter regulation both at national and European or international level and the expected evolution in industrial practices would trigger cost increases to comply with new HSE standards. Eni exploration and development plans to produce hydrocarbon reserves and drilling programs could also be affected by changing HSE regulations and industrial practices. Lastly, the Company expects that production royalties and income taxes in the oil&gas industry will probably increase in future years.

Moreover, in order to achieve the highest safety standards of our operations in the Gulf of Mexico, Eni entered into a consortium led by Helix that worked at the containment of the oil spill at the Macondo well. The Helix Fast Response System performs certain activities associated with underwater containment of erupting wells, evacuation of hydrocarbon on the sea surface, storage and transport to the coastline.

Worldwide Eni approach was to join international consortiums for main equipment and to develop in-house technologies to improve the intervention capability. Eni Emergency Response Kit consists of:

- Outsourced equipment contracted by Eni Head Quarter;
- Access Agreement to Subsea Capping Equipment consortium;
- Access Agreement to Global Dispersant Stockpile consortium;
- Eni Head Quarter proprietary equipment;
- Rapid Cube;
- Killing System.

As regards major accidents, the Seveso III (Directive No. 2012/18/EU) was adopted on July 4, 2012 and entered into force on August 13, 2012. Italy has transposed it into national legislation through the Legislative Decree No. 105/2015 (June 26, 2015).

The main changes in comparison to the previous Seveso Directive are:

- technical updates to take into account the changes in EU chemical classification, mainly regarding the 2008 European CLP Regulation of substances and mixtures;
- expanded public information about risks resulting from Company activities;
- modified rules in participation by the public in land-use planning projects related to Seveso plants; and
- stricter standards for inspections of Seveso establishments.

Eni has carried out specific activities aimed at guaranteeing the compliance of its own industrial sites.

HSE activity for the year 2018

Eni is committed to continuously improving its model for managing health, safety and environment issues across all its businesses in order to minimize risks associated with its own industrial activities, ensure reliability of its industrial operations and comply with all applicable rules and regulations.

In 2018, Eni's business units continued to obtain certifications of their management systems, industrial installations and operating units according to the most stringent international standards. The total number of certifications achieved was 294, of which:

- 88 certifications according to the ISO 14001 standard;
- 10 registrations according to the EMAS regulation (EMAS is the Environmental Management and Audit Scheme recognized by the European Union);
- 22 certifications according to the ISO 50001 standard (certification for an energy management system);
- 95 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems – requirements) and 6 according to the new ISO 45001 standard;
- 40 according to the ISO 9001 standard (certification of the quality management system).

In 2018 the percentage of Eni industrial installations and operating units with a significant HSE risk covered by certification is 94% for the OHSAS 18001/ISO 45001 standard and 93% for the ISO 14001 standard.

In 2018, total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to €1,254 million (+14% vs 2017).

Environment. In 2018, Eni incurred total expenditures of €914 million for the protection of the environment (with an increase of 21% with respect to 2017). Environmental expenditures are mainly related to remediation and reclamation activities (€374 million), waste management (€224 million), water management (€131 million), air protection (€66 million) and spill prevention (€41 million).

Safety. Eni is committed to safeguarding the safety of its employees, contractors and all people living in the areas where its activities are conducted and its assets located. In 2018, the new legislation didn't impact significantly procedures already in place for safety in the workplace.

The dissemination of safety culture is a value for Eni. In 2018, in order to increase safety's culture in the workforce, awareness-raising initiatives continued and a new one was launched.

Below the main initiatives 2018 to strengthen the safety culture:

- Safety starts @ home: realization of videos, based on safety golden rules, on safe behavior even at home
- Inside Lesson Learned Project: dissemination and sharing of the most significant lessons learned through video clips in Italy and abroad;

- Io vivo sicuro: theatrical events or roundtables to raise awareness among top management, contractors and external guests
- Process safety workshop and newsletter: two workshops were organized on the following topics “Fire prevention” and “Pressure equipment”, aimed at professionals in the safety field, and Eni personnel engaged in technical, technological and plant manager services. Quarterly newsletter on process safety were disseminated at company level.

In 2013, Eni launched an initiative aimed at issuing work permits in electronic form for standardizing and improving the related risk assessment process. The initiative is progressively involving all the operating sites.

In 2015, Eni developed the Company Process Safety Management System for increasing the safety of its operations through still higher technical and management standards. Starting from 2016 and in following years these standards are applied progressively in all operating activities.

Despite all the initiatives and activities carried out in 2018, the Total Recordable Injury Rate for the workforce worsened by 6% compared to 2017 (0.35 vs 0.33).

Regarding emergency preparedness to oil spill, Eni has joined the Oil Spill Response-Joint Industry Project (OSR-JIP I & II) which was launched in December 2011 by International Association of Oil&Gas Producers (IOGP) and International Petroleum Industry Environmental Conservation Association (IPIECA) and concluded in 2016 set-up after the Macondo accident.
The OSR-JIP aimed at:

- providing a forum for industry to share knowledge on the science, tools and techniques;
- representing the industry on approaches for oil spill preparedness and response, working closely with other associations on communications with both national and global regulatory groups;
- engaging pro-actively in broader outreach and communication.

The OSR-JIP carried out specific projects dealing with exercise planning, in situ burning, dispersants advocacy-subsea, efficacy-post spill monitoring, upstream risk assessment and response capability, etc., publishing 11 Research Reports, 9 Technical Reports and 24 Good Practice Guidance Eni participates at two Global Initiatives jointly led by the IMO and IPIECA: OSPRI (Black Sea, Caspian Sea and Central Eurasia) and WACAF (West, Central and Southern Africa).

Costs incurred in 2018 to support the safety levels of operations and to comply with applicable rules and regulations were €260 million.

Health. Eni’s activities for protecting health aim to continuously improve the psychophysical wellbeing of people in the workplace. Eni believes that it achieved a good performance in this area thanks to:

- plant and facility efficiency and reliability;
- promotion and dissemination of knowledge, adoption of best practices and operating management systems based on advanced criteria of protection of health and internal and external environment;
- certification programs of management systems for production sites and operating units;
- identified indicators in order to monitor exposure to chemical and physical agents;
- strong engagement in health protection for workers operating worldwide also with the support of international health providers capable of guaranteeing a prompt and adequate response to any emergency;
- identification of an effective and reliable health providers, in Italy and abroad;
- training programs for medics and paramedics.

In order to protect the health and safety of its employees, Eni relies on a network of health care facilities located in its main operating areas. A set of international agreements with the best local and international health providers ensures efficient services and timely responses to emergencies.

Eni is engaged to the elaboration of HIA and relative standards to be applied to all new projects of evaluation of working exposure to environment, in Italy and abroad. The main aim of HIA is to avoid any negative impacts and maximize any positive impacts of the project on the host community and it is usually carried out as part of/or in conjunction with the Health, Environmental and a Social Impact Assessment process. Its results are used to develop appropriate mitigation measures and an improvement plan with the host community.

Information about Eni's strategy and targets in a low-carbon scenario in accordance to standards set by the Task Force on climate-related Financial Disclosures (TCFD) of the Financial Stability Board and other non-financial information about sustainability is provided in the “Non-financial Information report” which is part of Eni’s 2018 Annual Report published in accordance with Italian law and practice. These reports are not incorporated by reference in this Form 20-F.

Regulation of Eni's businesses

Overview

The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.

Regulation of exploration and production activities

Eni's exploration and production activities are conducted in many countries and are therefore subject to a broad range of legislation and regulations. These cover virtually all aspects of exploration and production activities, including matters such as license acquisition, production rates, royalties, pricing, environmental protection, export, taxes and foreign exchange. The terms and conditions of the leases, licenses and contracts under which these oil&gas interests are held vary from country to country. These leases, licenses and contracts are generally granted by or entered into with a government entity or state company and are sometimes entered into with private property owners. These arrangements usually take the form of licenses or production sharing agreements.

Licenses (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a license, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the license holder is entitled to all production minus any production taxes or royalties, which may be in cash or in-kind. Concession contracts currently applied mainly in Western countries regulating relationships between States and oil companies with regards to hydrocarbon exploration and production activity. Both exploration and production licenses are generally for a specified period of time (except for production licenses in the United States which remain in effect until production ceases). The term of Eni's licenses and the extent to which these licenses may be renewed vary by area. Contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. The company holding the mining concession has an exclusive right on exploration, development and production activities, sustaining all the operational risks and costs related to the exploration and development activities, and it is entitled to the productions realized. As a compensation for mineral concessions, pays royalties on production (which may be in cash or in-kind) and taxes on oil revenues to the state in accordance with local tax legislation.

Proved reserves to which Eni is entitled are determined by applying Eni's share of production to total proved reserves of the contractual area, in respect of the duration of the relevant mineral right.

Eni operates under Production Sharing Agreement (PSA) in several foreign jurisdictions mainly in African, Middle Eastern and Far Eastern countries. The mineral right is awarded to the national oil company jointly with the foreign oil company that has an exclusive right to perform exploration, development and production activities and can enter into agreements with other local or international entities. In this type of contract, the national oil company assigns to the international contractor the task of performing exploration and production with the contractor's equipment (technologies) and financial resources. Exploration risks are borne by the contractor and production is divided into two portions: "Cost Oil" is used to recover costs borne by the contractor and "Profit Oil" is divided between the contractor and the national company according to variable schemes and represents the profit deriving from exploration and production. Further terms and conditions of these contracts may vary from country to country.

Pursuant to these contracts, Eni is entitled to a portion of a field's reserves, the sale of which is intended to cover expenditures incurred by the Company to develop and operate the field. The Company's share of production volumes and reserves representing the Profit Oil includes the share of hydrocarbons which corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. Therefore, the Company recognizes at the same time an increase in the taxable profit, through the increase in revenues, and a tax expense. Proved reserves to which Eni is entitled under PSAs are calculated so that the sale of production entitlements should cover expenses incurred by the Group to develop a field (Cost Oil) and recognize the Profit Oil set contractually (Profit Oil). A similar scheme to PSA applies to Service contracts.

In general, Eni is required to pay income tax on income generated from production activities (whether under a license or PSA). The taxes imposed upon oil&gas production profits and activities may be substantially higher than those imposed on other businesses.

Regulation of the Italian hydrocarbons industry

The matters regarding the effects of recent or proposed changes in Italian legislation and regulations or EU directives discussed below and elsewhere herein are forward-looking statements and involve risks and uncertainties that could cause the actual results to differ materially from those in such forward-looking statements. Such risks and uncertainties include the precise manner of the interpretation or implementation of such legal and regulatory changes or proposals, which may be affected by political and other developments.

Exploration & Production

The Italian hydrocarbons industry is regulated by a combination of constitutional provisions, statutes, governmental decrees and other regulations that have been enacted and modified from time to time, including legislation enacted to implement EU requirements (collectively, the "Hydrocarbons Laws").

Exploration permits and production concessions. Pursuant to the Hydrocarbons Laws, all hydrocarbons existing in their natural condition in strata in Italy or beneath its territorial waters (including its continental shelf) are the property of the State. Exploration activities require an exploration permit, while production activities require an exploiting concession, in each case granted by the Minister of Economic Development. The initial duration of an exploration permit is six years, with the possibility of obtaining two three-year extensions and an additional one-year extension to complete activities underway. Upon each of the three-year extensions, 25% of the area under exploration must be relinquished to the State (only for initial acreages larger than 300 square kilometers). The initial duration of a production concession is 20 years, with the possibility of obtaining a ten-year extension and additional five-year extensions until the field depletes.

These provisions are to be coordinated with a new law effective as of February 12, 2019, which requires certain Italian administrative bodies to adopt within eighteen months a plan indented to identify areas that are suitable for carrying out exploration, development and production of hydrocarbons in the national territory, including the territorial seawaters. Until approval of such a plan, it is established a moratorium on exploration activities, including the award of new exploration leases. Following the plan approval, exploration permits resume their efficacy in areas that have been identified as suitable; on the contrary, in unsuitable areas, exploration permits are repealed. As far as development and production concessions are concerned, pending the national plan approval ongoing concessions retain their efficacy and administrative procedures underway to grant extension to expired concession remain unaffected; instead no applications to obtain new concession can be filed. Once the above mentioned national plan is adopted, development and production concessions that fall in suitable areas can be granted further extensions and applications for new concessions can be filed; on the contrary development and production concessions current at the approval of the national plan that fall in unsuitable areas are repealed at their expiration and no further extensions can be granted, nor new concession applications can be filed. In case Italian administrative bodies fail to adopt the national plan for suitable areas within two years from the law enactment, the general moratorium on exploration activities is revoked and application for new concession permits can be filed. According to the statute, areas that suitable to the activities of exploring and developing hydrocarbons must conform to a number of criteria including morphological characteristics and social, urbanistic and industrial constraints, with particular bias for the hydrogeological balance, current territorial planning and with regard to marine areas for externalities on the ecosystem, reviews of marine routes, fishing and any possible impacts on the coastline.

Royalties. The Hydrocarbons Laws require the payment of royalties for hydrocarbon production. As per Legislative Decree No. 625 of November 25, 1996, subsequent modifications and integrations and Law Decree No. 83 of June 22, 2012, royalties are equal to 10% for gas and oil productions onshore, to 10% for gas and 7% for oil offshore, with fixed amount of exemption. Only in the Autonomous Region of Sicily, following the Regional Law No. 9 of May 15, 2013, royalties onshore for oil and gas are equal to 20,06%, with no exemptions).

Gas & Power

Natural gas market in Italy

New liberalization measures in Italy

Law Decree No. 1 enacted by the Italian Government on January 24, 2012, the so-called Liberalization

Decree, was converted to Law No. 20 on March 24, 2012. This law aimed at:

- enhancing competitiveness in gas tariffs to residential customers. The Italian authority in charge with setting pricing mechanisms for gas supplies to certain categories of end-users (ARERA) started from the second quarter of 2012 a process to revise the indexation mechanism of the raw material component by gradually increasing the weight of spot prices in the indexation of the supply costs of gas thus replacing the oil-linked indexation (see below); and

- reforming the storage system introducing market-based mechanisms for the allocation of storage capacity, moving away from the traditional "pro-rata"/tariff system, and with the aim to reduce the cost of natural gas for industrial customers. In particular:
  - for an amount determined by the Ministry itself, storage capacity started to be primarily reserved for the offer to industrial sector of an integrated service (international transport of liquefied natural gas, regasification and storage), thus allowing industrial clients to supply natural gas directly from abroad in the form of liquefied natural gas; and
  - the remaining amount of storage capacity started to be assigned via auction procedures devoted to the modulation needs.

Based on the principles described above, the Minister of Economic Development and the ARERA are due to establish yearly detailed criteria for the allocation of gas storage capacities.

In 2017, 1.5 BCM of integrated storage and regasification capacity was offered to the industrial sector.

Such integrated service is no longer offered since 2018, due to a new market-based mechanism for allocating regasification capacities in Italy introduced by the Italian regulator. With three operating LNG regasification terminals, Italy has a lot of regasification capacity, about half of which was not used in 2017. The Adriatic LNG terminal has a capacity of 8 billion cubic metres (BCM)/year, while capacity at OLT and Panigaglia is 3.75 BCM/y and 3.5 BCM/y, respectively. The low interest in accessing to and using regasification capacity on a spot or monthly basis is mainly due to the high level of regasification tariffs in Italy compared to the rest of Europe. The new market-based system for allocating regasification capacity in Italy is working on principles similar to the ones already set for the mechanisms for allocating storage capacity and it is therefore based on auctions that will express the market-value of the regasification capacity. Such new mechanism is likely to attract more LNG deliveries to the country in the future.

Management believes that these new regulation will increase competition in the wholesale natural gas market in Italy, leading to possible margin pressures.

Negotiation platform for gas trading and gas balancing market and other measures to increase gas market liquidity

In compliance with the provisions of Law No. 99 of July 23, 2009, on March 18, 2010, the Ministry of Economic Development published a decree that implements a trading platform for natural gas starting from May 10, 2010, aimed at increasing competition and flexibility on wholesale markets. Management and organization of this platform (MGAS) are entrusted to an independent operator, the Gestore dei Mercati Energetici (GME), an Italian agency. In the MGAS, parties authorized to carry out transactions at the "Punto di Scambio Virtuale" (PSV – Virtual Trading Point) may make forward and spot purchases and sales of volumes of natural gas. In the MGAS, GME plays the role of central counterparty to the transactions concluded by Market Participants.

In October 2016 the new gas balancing regime – an evolution of the one already in place – has entered into force in the Italian system in compliance with the EU regulatory framework. This system is based on the principle that network users have to balance their daily position, also in accordance with the timely information provided by Snam Rete Gas about the daily gas consumption. The new gas balancing regime provides for:

- the possibility for shippers to modify intra-day the gas nominations;
- the possibility for shippers to trade on the market with other shippers and/or with the TSO itself (that can access the market under some constraints, in order to address overall system balancing needs that may arise on top of shippers' activities)
- the incentive for shippers to balance their position via penalizing imbalance prices.

To foster market liquidity, starting from April 2017 all of the above-mentioned gas trading activities were concentrated on the MGAS, managed by GME, as one single platform.

In addition, since February 2018 voluntary market making activity has been introduced in the spot section of the gas exchange MGAS. Such activity is based on the service provided by some Liquidity Providers, in order to boost liquidity and trading activity on the same exchange, initially for the day-ahead market but with possible future extension to the within-day section and to the forward section of the MGAS.

Management believes that these measures have increased, and will further increase, the level of liquidity in the Italian spot market of gas.

Natural gas prices in the retail sector

Following the liberalization of the natural gas sector introduced in the year 2000 by Decree No. 164, prices of natural gas in the wholesale market which includes industrial and power generation customers are freely negotiated. However, the ARERA retains a power of surveillance on this matter as per Law No. 481/1995 (establishing the ARERA) and Legislative Decree No. 164/2000. Furthermore, the ARERA is still entrusted (as per the Presidential Decree dated October 31, 2002) with the power of regulating natural gas prices to residential customers, also with a view of containing inflationary pressure deriving from increasing energy costs. Consistently with those provisions, companies which sell natural gas to residential customers are currently required to offer to those customers the regulated tariffs set by ARERA beside their own price proposals.

In 2013, a new tariff regime was fully enacted by ARERA targeting Italian residential clients who are entitled to be safeguarded in accordance with current regulations. Clients who are eligible for the tariff mechanism set by the ARERA are residential clients (principally households, including residential buildings consuming less than 200,000 CM/y). With Resolution No. 196 effective from October 1, 2013, the ARERA reformulated the pricing mechanism of gas supplies to those customers by providing a full indexation of the raw material cost component of the tariff to spot prices at the TTF (Title Transfer Facility) hub in Northern Europe, replacing the then current regime that provided a mix between an oil-based indexation and spot prices.

The new tariff regime intended to partially offset the negative impact born by wholesalers due to possible indexation mismatches by introducing a pricing component intended to compensate wholesalers for losses that they would incur on those risks. Furthermore, it was provided a stability mechanism whereby a wholesaler part of a long-term, take-or-pay gas supply contract could opt to be reimbursed for the possible negative difference between the oil-linked costs of gas supplies and spot prices in the two thermal years following the implementation of the new regime; conversely, in case spot prices would fall below the oil-linked cost of gas supplies in the following two thermal years, the same wholesaler had to refund customers of the difference. Those provisions explicated their effects in 2014 – 2016.

This tariff regime also reduced the tariff components intended to cover storage and transportation costs. Finally, it also increased the specific pricing component intended to remunerate certain marketing costs incurred by retail operators, including administrative and retention costs, losses incurred due to customer default and a return on capital employed.

This new tariff indexation aiming at safeguarding the purchase-power of households was initially intended to remain effective till July 1, 2019 (as provided by Law 124/17). However, this deadline has been prorogated by one year (as per Law Decree 91/2018). From that point onwards, households in Italy will no longer have access to regulated tariffs for gas supplies. Consumers will have to choose among the different pricing proposals made by gas selling companies. The ARERA has established that gas selling companies comply with certain requirements about the offerings to customers which include at least two pricing indexations (fixed and variable), both complemented with contractual conditions regulated by the ARERA. Management believes that this development will increase competition in the Italian retail market for selling gas.

Other regulatory developments in the gas and electric sector in Italy

The Italian ARERA is currently reviewing gas transport tariffs along the Italian backbones to define tariff criteria intended to allow gas transport operators recover their operating costs for the next three-year time frame. This could potentially open opportunities to gas shippers, like Eni, due to the proposed elimination of long-term, ship-or-pay contracts at the points of access to the Italian national transport system. It is worth mentioning that an administrative measure introduced by ARERA effective from thermal year 2017 – 2018 helped gas shippers to recover part of the sunk costs associated with transport capacities at the points of access to the Italian network, which were booked by the shippers through multi-year arrangements. According to this measure, any unfilled transport capacity at the expiration of those multi-year arrangements may be recovered in the subsequent three-year time frame, with a net benefit to logistic costs.

Refining and marketing of petroleum products

Refining. The current regulations on refining activity in Italy provides that Italian administrative bodies authorize plans filed by refining operators intended to set up new processing and storage plants and to upgrade capacity, while all other changes that do not affect capacity can be freely implemented. This regime was streamlined by Law Decree No. 5/2012 that defined mineral oil processing and storage plants as "strategic installations" that need authorization from the State, in agreement with the local administrations. The Decree introduced a unitized process of authorization that must be finalized within 180 days, subject to compliance with applicable environmental regulations. the company has not experienced any material delays in obtaining relevant concessions for the upgrading of the Sannazzaro underway.

Marketing. Following the enactment of the above-mentioned Law Decree No. 1 on January 24, 2012, certain measures are expected to be introduced in order to increase levels of competition in the retail marketing of fuels. The rules regulating relations between oil companies and managers of service stations have been changed introducing the difference between principal and non-principal of a service station. Starting from June 30, 2012, principals will be allowed to freely supply up to 50% of their requirements. In such case, the distributing company will have the option to renegotiate terms and conditions of supplies and brand name use. As for non-principals, the law allows the parties to renegotiate terms and conditions at the expiration of existing contracts and new contractual forms can be introduced in addition to the only one allowed so far, i.e. exclusive supply. The law also provides for an expansion of non-oil sales.. Furthermore, the law 205/2017 provides some measures for preventing of tax evasion in the sale of oil products that in the past produced anticompetitive effects on the sector. The law requires the advance payment of Value Added Tax (VAT) on oil products before the extraction from deposits or the sale to consumer.

Service stations. Legislative Decree No. 32 of February 11, 1998, as amended by Legislative Decree No. 346 of September 8, 1999 and Law Decree No. 383 of October 29, 1999, as converted in Law No. 496 of December 28, 1999, significantly changed Italian regulation of service stations. Legislative Decree No. 32 replaces the system of concessions granted by the Ministry of Industry, regional and local authorities with an authorization granted by city authorities while the Legislative Decree No. 112 of March 31, 1998 still confirms the system of such concessions for the construction and operation of service stations on highways and confers the power to grant to Regions. Decree No. 32 also provides for: (i) the testing of compatibility of existing service stations with local planning and environmental regulations and with those concerning traffic safety to be performed by city authorities; (ii) the option to extend by 50% the opening hours (currently 52 hours per week) and a generally increased flexibility in scheduling opening hours; (iii) simplification of regulations concerning the sale of non-oil products and the permission to perform simple maintenance and repair operations at service stations; and (iv) the opening up of the logistics segment by permitting third-party access to unused storage capacity for petroleum products. Subsequently, various regulations have been enacted in Italy with the aim of improving network efficiency, modernizing service stations and opening up the market. Currently, all service stations are provided with self-service equipment and the sale of non-oil products has been broadly introduced by local administrative bodies. Law Decree No. 1/2012 also allowed the installation of fully automated service stations with prepayment, but only outside city areas. Law No. 133 of August 6, 2008, by intervening in competition provisions, removes some national and regional regulations, which might limit the liberty of establishment and introduces new provisions particularly concerning the elimination of restrictions concerning distances between service stations, the obligation to undertake non-oil activities and the liberalization of opening hours.

The new regulatory framework provided by the legislative decree No 257/2016 – implementing EU Directive 2014/94/UE on alternative fuel infrastructures – has introduced minimum requirements for the construction of infrastructure for the development of alternative fuels to mitigate the environmental impacts of the transport sector. The legislation established, furthermore, an adequate number of charging stations accessible to the public to be created throughout the country by 2020.

Finally, Law no. 124/2017 aims to promote the structural reorganization of the fuel distribution network also in order to increase competition and efficiency. The law requires the closure of fuel stations that are incompatible with road safety regulations and environmental streamlining procedures for the decommissioning.

Management believes that these measures will favor competition in the Italian retail market and enhance the competitiveness of efficient players.

In order to support the achievement of the renewables target in the transport sector established by the EU and national laws, the Ministerial Decree of 2 March 2018, provides the legislative framework to incentivize the production of both biomethane and other advanced biofuels to be used in the transport sector.

The Decree provides incentives for plants starting operations between 2018 and 2022 and to plants that are converted to biomethane production.

The incentive consists in an allocation of a Certificate (CIC) for every 10 Gcal of biomethane produced. The certificate has a market value since fossil fuel marketers have to sell a minimum percentage of biofuels annually, for which they receive the same Certificates.

In order to access to incentives, producers must comply with legal and technical regulations governing the quality and certification of the produced biomethane, verified by the competent Authority (Gestore dei Servizi Energetici, GSE).

These measure aims to favor advanced biofuels production through the valorization of waste, notably of agricultural and farm/zoo technical waste.

Petroleum product prices. Petroleum products' prices were completely deregulated in May 1994 and are now freely established by operators. Oil and gas companies periodically report their recommended prices to the Ministry of Economic Development; such recommendations are considered by service station operators in establishing retail prices for petroleum products.

Compulsory stocks. According to Legislative Decree of January 31, 2001, No. 22 ("Decree 22/2001") enacting Directive No. 1993/98/EC (which regulates the obligation of Member States to keep a minimum amount of stocks of crude oil and/or petroleum products) compulsory stocks, must be at least equal to the quantities required by 90 days of consumption of the Italian market (net of oil products obtained by domestically produced oil). In order to satisfy the agreement with the International Energy Agency (Law No. 883/1977), Decree No. 22/2001 increased the level of compulsory stocks to reach at least 90 days of net import, including a 10% deduction for minimum operational requirements. Decree No. 22/2001 states that compulsory stocks are determined each year by a decree of the Minister for Economic Development based on domestic consumption data of the previous year, defining also the amounts to be held by each oil company on a site-by-site basis. The Legislative Decree No. 249/2012, entered into force on February 10, 2013 to implement the Directive No. 2009/119/EC (imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products), sets forth in particular: (a) that a high level of oil security of supply through a reliable mechanism to assure the physical access to oil emergency and specific stocks shall be kept; and (b) the institution of a Central Stockholding Entity under the control of the Ministry for Economic Development that should be in charge of: (i) the purchase, holding, sell and transportation of specific stocks of products; (ii) the stocktaking; (iii) the statistics on emergency, specific and commercial stocks; and, eventually (iv) the storage and transportation service of emergency and commercial stocks in favor of sellers of petroleum products not vertically integrated in the oil chain. As of December 31, 2018, Eni owned 5.1 mmtonnes of oil products inventories, of which 3.4 mmtonnes as "compulsory stocks", 1.5 mmtonnes related to operating inventories in refineries and deposits (including 0.2 mmtonnes of oil products contained in facilities and pipelines) and 0.2 mmtonnes related to specialty products. Eni's compulsory stocks were held in term of crude oil (34%), light and medium distillates (36%), refinery feedstock (21%), fuel oil (4%) and other products (5%) were located throughout the Italian territory both in refineries (84%) and in storage sites (16%).

Competition

Like all Italian companies, Eni is subject to Italian and EU competition rules. EU competition rules are set forth in Articles 101 and 102 of the Lisbon Treaty on the Functioning of the European Union entered into force on December 1, 2009 ("Article 101" and "Article 102", respectively being the result of the new denomination of former Articles 81 and 82 of the Treaty of Rome as amended by the Treaty of Amsterdam dated October 2, 1997 and entered into force on May 1, 1999) and EU Merger Control Regulation No. 139 of 2004 (EU Regulation 139). Article 101 prohibits collusion among competitors that may affect trade among Member States and that has the object or effect of restricting competition within the EU. Article 102 prohibits any abuse of a dominant position within a substantial part of the EU that may affect trade among Member States. EU Regulation 139 sets certain turnover limits for cross-border transactions, above which enforcement authority rests with the European Commission and below which enforcement is carried out by national competition authorities, such as the Antitrust Authority in the case of Italy. On May 1, 2004, a new regulation of the European Council came into force (No. 1/2003) which substitutes Regulation No. 17/1962 on the implementation of the rules on competition laid down in Articles 101 and 102 of the Treaty. In order to simplify the procedures required of undertakings in case of conducts that potentially fall within the scope of Article 101 and 102 of the Treaty, the new regulation substitutes the obligation to inform the Commission with a self-assessment by the undertakings that such conducts do not infringe the Treaty. In addition, the burden of proving an infringement of Article 101(1) or of Article 102 of the Treaty shall rest on the party or the authority alleging the infringement. The undertaking or association of undertakings claiming the benefit of Article 101(3) of the Treaty shall bear the burden of proving that the conditions of that paragraph are fulfilled. The regulation defines the functions of authorities guaranteeing competition in Member States and the powers of the Commission and of national courts. The Competition Authorities of the Member States shall have the power to apply Articles 101 and 102 of the Treaty in individual cases. For this purpose, acting on their own initiative or on a complaint, they may take the following decisions:

- requiring that an infringement be brought to an end;
- ordering interim measures;
- accepting commitments; and
- imposing fines, periodic penalty payments or any other penalty provided for in their national law.

National courts shall have the power to apply Articles 101 and 102 of the Treaty. Where the Commission, acting on a complaint or on its own initiative, finds that there is an infringement of Article 101 or of Article 102 of the Treaty, it may: (i) require the undertakings and associations of undertakings concerned to bring such infringement to an end; (ii) order interim measures; (iii) make commitments offered by undertakings to meet the concerns expressed to them by the Commission binding on the undertakings; and (iv) find that Articles 101 and 102 of the Treaty are not applicable to an agreement for reasons of Community public interest. Eni is also subject to the competition rules established by the Agreement on the European Economic Area (the "EEA Agreement"), which are analogous to the competition rules of the Lisbon Treaty (ex Treaty of Rome) and apply to competition in the European Economic Area (which consists of the EU and Norway, Iceland and Liechtenstein). These competition rules are enforced by the European Commission and the European Free Trade Area Surveillance Authority. In addition, Eni's activities are subject to Law No. 287 of October 10, 1990 (the "Italian Antitrust Law"). In accordance with the EU competition rules, the Italian Antitrust Law prohibits collusion among competitors that restricts competition within Italy and prohibits any abuse of a dominant position within the Italian market or a significant part thereof. However, the Italian Antitrust Authority may exempt for a limited period agreements among companies that otherwise would be prohibited by the Italian Antitrust Law if such agreements have the effect of improving market conditions and ultimately result in a benefit for consumers.

Property, plant and equipment

Eni has freehold and leasehold interests in real estate in numerous countries throughout the world. The Company enters into operating lease contracts with third parties to hire plant and equipment such as floating production and storage offloading vessels (FPSO), drilling rigs, time charter, service stations and other equipment. Management believes that certain individual petroleum properties are of major significance to Eni as a whole. Management regards an individual petroleum property as material to the Group in case it contains 10% or more of the Company' worldwide proved oil&gas reserves and management is committed to invest material amounts of expenditures in developing it in the future. See "Exploration & Production" above for a description of Eni's both material and other properties and reserves and sources of crude oil and natural gas.

Organizational structure

Eni SpA is the parent company of the Eni Group. As of December 31, 2018, there were 213 subsidiaries and 103 associates, joint ventures and joint operations that were accounted for under the equity or cost method or in accordance to Eni's share of revenues, costs and assets of the joint operations calculated based on Eni's working interest. Information on Eni's investments as of December 31, 2018 is provided in the notes to the Consolidated Financial Statements.

Item 4A. UNRESOLVED STAFF COMMENTS

None.

Item 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

This section is the Company's analysis of its financial performance and of significant trends that may affect its future performance. It should be read in conjunction with the Key Information presented in Item 3 and the Consolidated Financial Statements and related Notes thereto included in Item 18. The Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards as issued by the IASB.

This section contains forward-looking statements, which are subject to risks and uncertainties. For a list of important factors that could cause actual results to differ materially from those expressed in the forward-looking statements, see the cautionary statement concerning forward-looking statements on page ii.

Executive summary

Key consolidated financial data

		2018	2017	2016
			(€ million)	
Net sales from operations from continuing operations		75,822	66,919	55,762
Operating profit (loss) from continuing operations		9,983	8,012	2,157
Net profit (loss) attributable to Eni from continuing operations		4,126	3,374	(1,051)
Net profit (loss) attributable to Eni from discontinued operations				(413)
Net profit (loss) attributable to Eni		4,126	3,374	(1,464)
Net cash provided by operating activities – continuing operations		13,647	10,117	7,673
Capital expenditures – continuing operations		9,119	8,681	9,180
Disposal of assets, consolidated subsidiaries and businesses		1,242	5,455	1,054
Shareholders' equity including non-controlling interest at year end		51,073	48,079	53,086
Net borrowings at year end		8,289	10,916	14,776
Net profit (loss) attributable to Eni basic and diluted from continuing operations	(€ per share)	1.15	0.94	(0.29)
Dividend per share	(€ per share)	0.83	0.80	0.80
Ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage)[1]		0.16	0.23	0.28

(1) For a discussion of the usefulness and a reconciliation of these non-GAAP financial measures with the most directly comparable GAAP financial measures see – "Liquidity and capital resources – Financial Conditions" below.

Reported earnings

In the full year 2018, net profit attributable to Eni's shareholders was €4,126 million, up by 22.3% vs. the prior-year (€3,374 million); operating profit of €9,983 million represented a 24.6% increase over 2017 (up by approximately €2 billion).

Eni's results were supported by a better trading environment with average Brent prices increasing by 31% from 2017 to 71 $/barrel in 2018, in a highly volatile scenario. In the first ten months of the year, oil prices built on gains peaking at 85 $/barrel in October, the highest level in the last four years, due to a global economic recovery and a balanced demand/supply backdrop. Starting from November, alongside a sharp correction in the global financial markets, oil prices entered a downturn losing about 40% from the peak, falling to approximately 50 $/barrel at the end of the year, due to signs of weakening global growth, oversupplies, uncertainties tied to the commercial dispute between the USA and China and the Brexit, as well as geopolitical factors. In December, OPEC and Russia announced a production cut of 1.2 million barrel/d effective from 2019, which helped crude oil prices rebound to the sixty-dollars level in the first months of 2019.

In this scenario, Eni's E&P segment reported an increase in operating profit of €2.56 billion, leveraging on better prices and production increases, with the latter boosted by a shift in the production mix towards barrels with higher profitability. Hydrocarbons production rose to 1.73 mmBOE/d, with a 1.3% annual grow at constant prices (1% on reported basis), driven by Eni's successful strategy of reducing the time-to-market of its reserves as witnessed by five new field start-ups in the year and fast ramp-up at core projects like the Zohr gas field in Egypt. The reserve replacement ratio was 124% on all-sources basis;

when stripping out asset purchases and divestments the ratio was still 100%. The de-booking of proved reserves made at a project in Venezuela negatively affected the reserve replacement ratio by fifteen percentage points and was driven by a deteriorated operating environment.

The all-sources reserve replacement ratio improved significantly from the year-ago ratio of 27% due to the fact that in 2017 the Company divested significant interests in the properties of Zohr and Area 4 in Mozambique.

The G&P segment improved its operating profit by approximately €0.6 billion, driven by the overall restructuring of all the business lines. The Company was able to monetize the flexibilities associated with the portfolio of long-term gas contracts, as in the case of the option to lift additional volumes of gas beyond the minimum contractual take in case of favourable market trends like the ones that occurred in the first nine months of the year with a tighter gas market. Also, optimization in the power business and in logistics, as well as growth in the LNG business leveraging its integration with the E&P segment helped the segment's results.

The downstream oil and chemical businesses were negatively affected by a challenging trading environment (approximately down by €1.4 billion) because of rapidly-escalating oil-based feedstock costs in the first ten months of the year, which were not fully recovered in the final prices of products due to competitive pressure from more efficient producers and a slowdown in markets for oil and chemicals commodities in the final part of the year. Those market developments caused a squeeze in commodity margins (the SERM benchmark refining margin was down by 26% to 3.7 $/barrel; the cracker margin down by 11% and the polyethylene margin was down by 69%), the effects of which were partly offset by improved margins on retail sales of fuels and efficiency gains.

Adjusted results

Adjusted operating profit and adjusted net profit are determined by excluding from the reported results inventory holding gains or losses and non-core gains and losses (pre and post-tax, respectively).

Adjusted operating profit (or loss) and adjusted net profit (or loss) provide management with an understanding of the results from our underlying operations by excluding the effects of certain disposals and charges or gains that do not reflect the ordinary results of our operations. Adjusted measures of profitability are used to evaluate our period-over-period operating performance, as management believes these provide more comparable measures as they adjust for disposals and special charges or gains not reflective of the underlying trends in our business. These Non-GAAP performance measures may be useful to an investor in evaluating the underlying operating performance of our business, because the items excluded from the calculation of such measures can vary substantially from company to company depending upon accounting methods, management's judgment, book value of assets, capital structure and the method by which assets were acquired, among other factors.

In 2018, non-core items, including the gain of the initial recognition of Eni's interest in Vår Energi resulting from the business combination between the fully-owned subsidiary Eni Norge and Point Resources (as difference between the fair value of the investment and the book value of disposed net asset), the gain on the divestment of a 10% interest in the Zohr gas field, impairment losses and other non-core charges were a net negative of €388 million in net profit and of €1,161 million in operating profit. Furthermore, an inventory holding loss of €69 million (€96 million pre-tax) was recorded due to declining crude oil and products prices at end of the year reflected in the alignment of inventories at their net realizable values.

The Group underlying performance – i.e net of the effect of non-core gains and losses and the inventory holding loss – resulted in adjusted net profit for the year of €4,583 million compared to €2,379 million in 2017, and in adjusted operating profit of €11,240 million compared to €5,803 million in 2017, almost doubling y-o-y, up by €5.44 billion. The increase in adjusted operating profit was driven by higher results in the E&P segment which doubled its operating profit at €10,850 million, up by €5.68 billion, and by a recover in profitability at the G&P segment with a €0.33 billion gain. Price and margin effects accounted for €4 billion, while improvements in the underlying performance driven by production growth and a better volume mix in the E&P segment accounted for €1.4 billion.

The table below sets forth details of the identified non-core gains and losses included in the net results during the period presented.

Eni Group	Year ended December 31, 2018	2017	2016
	(€ million)		
(Profit) loss on inventory	96	(219)	(175)
Environmental provisions	325	208	193
Impairment losses (impairments reversals), net	866	(221)	(459)
Impairment of exploration projects			7
Net gains on disposal of assets	(452)	(3,283)	(10)
Risk provisions	380	448	151
Provision for redundancy incentives	155	49	47
Reinstatement of Eni Norge amortization charges(1)	(375)		
Fair value gains/losses on commodity derivatives	(133)	146	(427)
Reclassification of currency derivatives and exchange effects to management measure of business performance	107	(248)	(19)
Estimate revision of revenues accrued in the gas retail business		64	161
Valuation allowance of doubtful accounts(2)		616	410
Write-off of the damaged units of the EST conversion plant at the Sannazzaro refinery			193
Provision for removal and clean-up of EST conversion plant			24
Compensation gain on part of a third-party insurer relating to the EST plant incident			(217)
Other	288	231	279
Total net non-core items in operating profit	**1,257**	**(2,209)**	**158**
Finance expenses	(85)	502	116
of which: *reclassification of currency derivatives and exchange effects to management measure of business performance*	*(107)*	*248*	*19*
Capital gains on disposal of investments	(909)	(163)	(57)
Write downs of investments and financing receivables	67	537	483
Write down of deferred tax assets/utilization of deferred tax liabilities	99		170
Tax effects relating to the US tax reform		115	
Tax effects on the above listed items and other items	55	160	(214)
Tax effects on (profit) loss on inventory	(27)	63	55
Net non-core items in net profit	**457**	**(995)**	**711**
Net (charges) gains attributable to non-controlling interest			
Net non-core items attributable to Eni	**457**	**(995)**	**711**

(1) Management has evaluated to reinstate correlation between hydrocarbon production and reserve depletion by accruing the underlying UOP-based amortization charges of Eni Norge subsidiary classified in accordance to IFRS 5 due to the business combination with Point Resources. In the GAAP results, assets or disposal group held for sale are not to be depreciated or amortized.

(2) Includes credit losses in E&P for receivables in Nigeria and Venezuela and in the retail G&P business for the estimate made in accordance with the expected loss accounting model net of the estimate made in accordance to the incurred loss accounting for credit losses.

The table below provides a reconciliation of those Non-GAAP measures to the most comparable performance measures calculated in accordance with IFRS.

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
GAAP measure of operating profit	**9,983**	**8,012**	**2,157**
Inventory holding (gains) and losses	96	(219)	(175)
Identified net (gains) losses	1,161	(1,990)	333
Total net non-core items in operating profit	***1,257***	***(2,209)***	***158***
Non-GAAP measure of operating profit	**11,240**	**5,803**	**2,315**
GAAP measure of net profit	**4,126**	**3,374**	**(1,051)**
Inventory holding (gains) and losses, post tax	69	(156)	(120)
Identified net (gains) losses, post tax	388	(839)	831
Total net non-core items in net profit	***457***	***(995)***	***711***
Non-GAAP measure of net profit	**4,583**	**2,379**	**(340)**

Cash flow from operating activities amounted to €13,647 million for the full year of 2018 and was up by 35% y-o-y, driven by an improved underlying performance and scenario effects. Cash flow from operating activities was affected by a lower level of receivables due beyond the end of the reporting period being sold to financing institutions, compared to 2017 (approximately €280 million). Other positive cash flows were associated with positive changes in receivables and payables associated with investing activities (mainly including the cash-in of the deferred price of the Zohr disposals made in 2017), which amounted to €0.9 billion. Asset disposals amounted to €1.24 billion. Capital expenditure for the year, including investments, was €9.36 billion. That amount included the following items: entry bonuses paid in connection with the acquisition of interests in two producing Concession Agreements and a third under development in the UAE (€869 million); non-strategic acquisitions in the gas mid-downstream business (approximately €100 million); the expenditures pertaining to a 10% divested interest in the Zohr project (€170 million) incurred from January 1, 2018 to the closing of the transaction (end of June 2018), which were reimbursed to Eni by the buyer.

After having funded capital expenditures and the dividend of €2.95 billion, the positive cash inflows of 2018 resulted in a significant surplus, which increased the Group' s cash and cash equivalents on hand.

At December 31, 2018, the Group's net debt decreased by €2,627 million to €8,289 million. The Group ratio of finance debt to total equity at year-end 2018 was 0.51. However, in assessing the Group financial structure, management is using a measure of indebtedness, which subtracts cash and cash equivalents and other very liquid financial assets from finance debt. This Non-GAAP measure of indebtedness is defined "net borrowings" (see Glossary). The ratio of net borrowings to total equity is defined "Leverage" (see Glossary) and is commonly used by management in assessing the Group financial condition (see paragraph "Financial condition" below). Leverage at year-end 2018 decreased to 0.16 down from 0.23 at the end of 2017.

In 2019, we are projecting a capital expenditure budget of approximately €8 billion of which 80% relating to the E&P segment. That amount does not include the planned expenditures to acquire certain equity investments, particularly the acquisition of a 20% interest in the Ruwais refining complex in UAE with an expected expenditure of approximately €3 billion, which completion is forecast to occur by end of 2019.

We expect a production growth rate of approximately 2.5% compared to 2018 assuming constant crude oil prices and excluding portfolio transactions. Finally, we are projecting a cash dividend for the full year 2019 of €0.86 per share. See "Management expectations of operations".

Trading environment

	2018	2017	2016
Average price of Brent dated crude oil in U.S. dollars[(1)]	71.04	54.27	43.69
Average price of Brent dated crude oil in euro[(2)]	60.15	48.03	39.47
Average EUR/USD exchange rate[(3)]	1.181	1.130	1.107
Standard Eni Refining Margin (SERM)[(4)]	3.7	5.0	4.2
Euribor – three month euro rate %[(3)]	(0.32)	(0.33)	(0.26)

(1) Price per barrel. Source: Platt's Oilgram.

(2) Price per barrel. Source: Eni's calculations based on Platt's Oilgram data for Brent prices and the EUR/USD exchange rate reported by the European Central Bank (ECB).

(3) Source: ECB.

(4) In $/BBL FOB Mediterranean Brent dated crude oil. Source: Eni calculations. Approximates the margin of Eni's refining system in consideration of material balances and refineries' product yields.

When the term margin is used in the following discussion, it refers to the difference between the average selling prices and reflects the trading environment and is, to a certain extent, a gauge of industry profitability.

Eni's results of operations and the year-to-year comparability of its financial results are affected by a number of external factors which exist in the industry environment, including changes in oil, natural gas and refined products prices, industry-wide movements in refining margins and fluctuations in exchange rates and interest rates. Changes in weather conditions from year to year can influence demand for natural gas and some petroleum products, thus affecting results of operations of the natural gas business and, to a lesser extent, of the refining and marketing business. See "Item 3 – Risk factors".

In the first ten months of the year, oil prices built on gains peaking at 85 $/barrel in October, the highest level in the last four years, due to global economic growth and a balanced demand/supply backdrop. Starting from November, alongside a sharp correction in the global financial markets, oil prices entered a downturn losing about 40% from the peak, falling to approximately 50 $/barrel at the end of the year, due to signs of weakening global growth, oversupplies, uncertainties tied to the commercial dispute between the USA and China and Brexit, as well as geopolitical factors. In December, OPEC and Russia announced a production cut of 1.2 million barrel/d effective from 2019, which helped crude oil prices rebound to the sixty-dollars level in the first months of 2019.

Eni's refining margins (Standard Eni Refining Margin – SERM) which represents the benchmark for the level of profitability of Eni's refineries before fixed cash expenses, decreased from a year ago (down by 26%) to 3.7 $/BBL driven by the sharp increase of oil prices reported in the first ten months, not recovered in the sale prices of refining products due to competitive pressure in the markets. Assuming the budget scenario of exchange rates and oil spreads, the breakeven SERM of Eni refineries is in line with our earlier guidance.

The exchange rate of euro against the dollar for 2018 was 1.181, with an appreciation of 4.5% compared to the average exchange rate recorded in 2017.

Critical accounting estimates

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the carrying amounts of assets and liabilities, revenues and expenses reported in the financial statements, as well as amounts included in the notes thereto, including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience or other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas assets, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets, equity-accounted investments and goodwill, decommissioning and restoration liabilities, business combinations, pensions and other post-retirement benefits, and recognition of environmental liabilities. Although the Company uses its best estimates and judgments, actual results could differ from the estimates and assumptions used. A review of significant accounting estimates and judgemental areas is provided in "Item 18 – Note 1 to Consolidated Financial Statements".

2016 – 2018 Group results of operations

Overview of the profit and loss account for three years ended December 31, 2016, 2017 and 2018

The table below sets forth a summary of Eni's profit and loss account for the periods indicated. All line items included in the table below are derived from the Consolidated Financial Statements prepared in accordance with IFRS.

	Year ended December 31,		
	2018	**2017**	**2016**
		(€ million)	
Net sales from operations	75,822	66,919	55,762
Other income and revenues[1]	1,116	4,058	931
Total revenues	**76,938**	**70,977**	**56,693**
Operating expenses	(59,130)	(55,412)	(47,118)
Other operating (expense) income	129	(32)	16
Depreciation, depletion and amortization	(6,988)	(7,483)	(7,559)
Impairment reversal (impairment losses), net	(866)	225	475
Write-off	(100)	(263)	(350)
OPERATING PROFIT (LOSS)	**9,983**	**8,012**	**2,157**
Finance income (expense)	(971)	(1,236)	(885)
Income (expense) from investments	1,095	68	(380)
PROFIT (LOSS) BEFORE INCOME TAXES	**10,107**	**6,844**	**892**
Income taxes	(5,970)	(3,467)	(1,936)
Net profit (loss) – continuing operations	**4,137**	**3,377**	**(1,044)**
Net profit (loss) – discontinued operations			**(413)**
Net profit (loss)	**4,137**	**3,377**	**(1,457)**
Attributable to:			
Eni's shareholders:	**4,126**	**3,374**	**(1,464)**
- continuing operations	4,126	3,374	(1,051)
- discontinued operations			(413)
Non-controlling interest:	**11**	**3**	**7**
- continuing operations	11	3	7
- discontinued operations			

(1) Includes, among other things, contract penalties, income from contract cancellations, gains on disposal of mineral rights and other fixed assets, compensation for damages and indemnities and other income.

The table below sets forth certain income statement items as a percentage of net sales from operations for the periods indicated.

	Year ended December 31,		
	2018	**2017**	**2016**
		(%)	
Operating expenses	78.0	82.8	84.5
Depreciation, depletion, amortization, impairment reversal (impairment losses) net, write-off	10.5	11.2	13.3
OPERATING PROFIT	**13.2**	**12.0**	**3.9**

2018 compared to 2017. In the full year 2018, net profit attributable to Eni's shareholders was €4,126 million, up by 22.3% vs. the previous year result (€3,374 million); operating profit of €9,983 million represented a 24.6% increase over 2017 (up by approximately €2 billion). Eni's results benefitted from a better trading environment with average Brent prices increasing by 31% from 2017 to 71 $/barrel, in a highly volatile scenario. For further details see management discussion in the paragraph "Executive summary".

2017 compared to 2016. Net profit attributable to Eni's shareholders for the full year of 2017 was €3,374 million, a noticeable improvement over 2016, when a loss of €1,464 million was incurred from both continuing and discontinued operations, with the latter due to a charge on the Saipem shareholding following the loss of control over the investee. The reported operating profit for the full year of 2017 was €8,012 million, sharply higher than in 2016 (up by €5,855 million). The Eni Group recorded a substantial recovery in profitability across all business segments. This trend benefitted from higher commodity prices and margins and the progress in implementing the Group's strategy.

Analysis of the line items of the profit and loss account

a) Total revenues

Eni's revenues were €76,938 million, €70,977 million and €56,693 million for the years ended December 31, 2018, 2017 and 2016, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni's net sales from operations amounted to €75,822 million, €66,919 million and €55,762 million for the years ended December 31, 2018, 2017 and 2016, respectively, and its other income and revenues totaled €1,116 million, €4,058 million and €931 million, respectively, in these periods.

Net sales from operations

The table below sets forth, for the periods indicated, net sales from operations generated by each of Eni's business segments including intragroup sales, together with consolidated net sales from operations.

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
Exploration & Production	25,744	19,525	16,089
Gas & Power	55,690	50,623	40,961
Refining & Marketing and Chemicals	25,216	22,107	18,733
Corporate and other activities	1,589	1,462	1,343
Consolidation adjustments(1)	(32,417)	(26,798)	(21,364)
NET SALES FROM OPERATIONS	**75,822**	**66,919**	**55,762**

(1) Intragroup sales are included in net sales from operations in order to give a more meaningful indication as to the volume of the activities to which sales from operations by segment may be related. The largest intragroup sales are recorded by the Exploration & Production segment. "Item 18 – Note 35 – of the Notes on Consolidated Financial Statements" for a breakdown of intragroup sales by segment for the reported years.

2018 compared to 2017. Eni's net sales from operations (revenues) for 2018 (€75,822 million) increased by €8,903 million from 2017 (or up by 13.3%) primarily reflecting the recovery in commodity prices.

Revenues generated by the Exploration & Production segment (€25,744 million) increased by €6,219 million (or up by 31.9%). This was due to higher average realizations on equity hydrocarbons (oil realizations up by 30.8%; gas realizations up by 41% on average in dollar terms) driven by increasing prices for the marker Brent (up by 30.9%) and better gas prices due to tighter gas markets in certain geographies and the ramp-up of production with higher-than-average gas realizations.

Revenues generated by the Gas & Power segment (€55,690 million) increased by €5,067 million (or up by 10%). The increase reflected higher natural gas and power prices, as well as increased revenues from trading activity due to higher oil and products selling prices.

Revenues generated by the Refining & Marketing and Chemical segment (€25,216 million) increased by €3,109 million (or up by 14.1%) mainly in the Refining & Marketing business with an increase of €2,958 million due to higher commodity prices. The average selling prices of gasoline and gasoil reported an increase of 14% and 30%, respectively. Revenues generated in the Chemical segment slightly increased (up by €272 million) boosted by the increase in average selling prices as well as by higher volumes sold (up by 6%).

2017 compared to 2016. Eni's net sales from operations (revenues) for 2017 (€66,919 million) increased by €11,157 million from 2016 (or up by 20%) primarily reflecting higher realizations on oil, products and natural gas due to the recovery in commodity prices. Changes in sales volumes of products sold were immaterial.

Revenues generated by the Exploration & Production segment (€19,525 million) increased by €3,436 million (or up by 21.4%). This was due to higher average realizations on equity hydrocarbons (up by 20.3% on average in dollar terms) driven by increasing prices for the marker Brent (up by 24.2%) and gas benchmarks in Europe, in the United States and elsewhere which however appreciated by a smaller amount than oil realizations due to time lags in oil-linked pricing formulas.

Revenues generated by the Gas & Power segment (€50,623 million) increased by €9,662 million (or up by 23.6%). The increase reflected higher commodity prices and volumes purchased to be resold in the business of crude oil and refined products trading, as well as higher gas and power selling prices.

Revenues generated by the Refining & Marketing and Chemical segment (€22,107 million) increased by €3,374 million (or up by 18%) mainly reflecting a recovery in the commodities prices. The average selling prices of gasoline and gasoil reported an increase of 19% and 24%, respectively. The average selling prices in the Chemical business increased by 16% due to the recovery in the monomers (intermediates up by 27% and polymers up by 13%).

Other income and revenues

2018 compared to 2017. Eni's other income and revenues amounted to €1,116 million in the full year 2018 and mainly related to the gain on the divestment of a 10% interest in the Zohr project. The reduction of €2,942 million from the full year 2017 is due to the gains on disposals recorded in 2017 on the sale of a 40% interest in the Zohr gas field in Egypt (€1,281 million) and of a 25% interest in natural gas-rich Area 4 offshore Mozambique (€1,985 million).

2017 compared to 2016. Eni's other income and revenues for 2017 (€4,058 million) increased by €3,127 million from 2016 primarily reflecting gains on the disposal of a 40% interest in the Zohr gas field in Egypt (€1,281 million) and of a 25% interest in natural gas-rich Area 4 offshore Mozambique (€1,985 million).

b) Operating expenses

The table below sets forth the components of Eni's operating expenses for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
Purchases, services and other	55,622	51,548	43,278
Impairment losses (impairment reversals) of trade and other receivables, net	415	913	846
Payroll and related costs	3,093	2,951	2,994
Operating expenses	**59,130**	**55,412**	**47,118**

2018 compared to 2017. Operating expenses for 2018 (€59,130 million) increased by €3,718 million y-o-y, up by 6.7%, primarily reflecting higher supply costs of raw materials (natural gas under long-term supply contracts, refinery and chemical feedstock and hydrocarbons purchased for resale). Purchases, services and other costs included €705 million relating mainly to environmental provisions and the recognition of losses on certain contractual and commercial disputes. Payroll and related costs (€3,093 million) increased by €142 million from 2017, up by 4.8%, mainly due to the increase in average wages and higher provisions for redundancy incentives relating to an early retirement program in the Eni gas e luce subsidiary. These increases were partly offset by a reduction in the average number of employees outside Italy and the appreciation of the euro against the US dollar.

2017 compared to 2016. Operating expenses for 2017 (€55,412 million) increased by €8,294 million y-o-y, up by 17.6%, primarily reflecting higher supply costs of raw materials (natural gas under long-term supply contracts, refinery and chemical feedstock and hydrocarbons purchased for resale). Purchases, services and other costs included €660 million relating mainly to environmental provisions and the recognition of losses on certain contractual and commercial disputes (€360 million in 2016). Payroll and related costs (€2,951 million) decreased by €43 million from 2016, down by 1.4%, mainly due to the lower average number of employees and the appreciation of euro vs. the dollar and the GBP.

c) Depreciation, depletion, amortization, impairment losses (impairment reversals) net and write-off

The table below sets forth a breakdown of depreciation, depletion, amortization, impairment losses (impairment reversals) net and write-off for the periods indicated.

	Year ended December 31,		
	2018	**2017**	**2016**
		(€ million)	
Exploration & Production	6,152	6,747	6,772
Gas & Power	408	345	354
Refining & Marketing and Chemicals	399	360	389
Corporate and other activities	59	60	72
Impact of unrealized intragroup profit elimination[(1)]	(30)	(29)	(28)
Total depreciation, depletion and amortization	**6,988**	**7,483**	**7,559**
Impairment losses	1,292	862	1,067
Reversals of impairment losses	(426)	(1,087)	(1,542)
Write-off	100	263	350
Total depreciation, depletion, amortization, impairment losses (impairment reversals), net and write off	**7,954**	**7,521**	**7,434**

(1) This item concerned mainly intra-group sales of goods and capital, recorded at period end in the assests of the purchasing business segment.

2018 compared to 2017. In 2018, depreciation, depletion and amortization charges (€6,988 million) decreased by €495 million from 2017, or 6.6%, mainly in the Exploration & Production segment (a decrease of €595 million) due to the classification of Eni Norge subsidiary as held for sale in accordance to IFRS 5 from the second half of 2018 due to the pending business combination with Point Resources. After Eni Norge was classified as held for sale in accordance to IFRS 5, amortization ceased. The total amount of depreciation, depletion and amortization was also positively impacted by the appreciation of the euro, partly offset by fields started-up and new projects ramp-up.

In 2018, the Group recorded impairment losses at property, plant and equipment for a total amount of €1,292 million, mainly relating to: (i) impairment losses of oil&gas assets driven by a lower-than-expected performance at certain fields in Congo and in the USA, and the impairment of a mineral interest reflecting a worsening operating environment (for a total of €1,025 million), (ii) the write-down of capital expenditure relating to certain Cash Generating Units in the R&M business, which were impaired in previous reporting periods and continued to lack any profitability prospects (€156 million). These negatives were partly offset by the reversal of prior-year impairment losses at certain oil&gas assets driven by an improved outlook for gas prices in Italy and a reduction in the discount rate due to a reduced country-risk premium (for a total amount of €299 million) and at certain transportation activities outside Italy due to the reduction of the country risk premium factored in the discount rate (€66 million).

The write-off amounting to €100 million, mainly related to the costs of exploratory wells lacking the requisites for continuing capitalization because they did not encounter commercial quantities of hydrocarbons or due to lack of management commitment in pursuing further appraisal activity in Vietnam and Morocco.

2017 compared to 2016. In 2017, depreciation, depletion and amortization charges (€7,483 million) decreased by €76 million from 2016, or 1%, mainly in the Exploration & Production segment (with a decrease of €25 million) reflecting lower development capital expenditures of the year (down by 6.9%) and the euro appreciation, partially offset by start-ups and ramp-ups of new projects, and in the Refining & Marketing segment due to the write-off, reported in 2016, of the damaged units of the EST conversion plant following the accident occurred in December 2016.

In 2017, the Group recorded reversals of prior impairment losses in the E&P segment, at oil&gas properties for €808 million. These were driven by upward reserve revisions, lower future development and operating expenses, as well as a favourable impact in connection with the new corporate tax regime in the USA. The Gas & Power segment recorded the reversal of asset impairment losses recorded in previous reporting periods relating for €184 million to the alignment of the book value of the Hungarian gas distribution activity to its fair value, in light of a sale negotiation ongoing at the balance sheet date which may lead to a sale being completed in 2018. In the Refining & Marketing and Chemicals segment, an asset impairment reversal of €76 million reflected improved profitability prospects of the Chemical business. These reversals were partly offset by impairment losses relating to oil&gas properties in the upstream business (€650 million) driven by the project re-phasing or cancellation and downward reserve revisions. Finally, investments made for compliance and stay-in-business purposes were fully impaired at cash generating units previously written-off in the Refining & Marketing business, which were confirmed to lack any prospects of profitability (€130 million).

The write-off amounting to €263 million, mainly related to the costs of exploratory wells lacking the requisites for continuing capitalization because they did not encounter commercial quantities of hydrocarbons or due to lack of management commitment in pursuing further appraisal activity in Egypt, Norway and the Ivory Coast.

d) Operating profit (loss) by segment

The table below sets forth Eni's operating profit by business segment for the periods indicated.

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
Exploration & Production	10,214	7,651	2,567
Gas & Power	629	75	(391)
Refining & Marketing and Chemicals	(380)	981	723
Corporate and other activities	(691)	(668)	(681)
Impact of unrealized intragroup profit elimination	211	(27)	(61)
Operating profit (loss)	**9,983**	**8,012**	**2,157**

The table below sets forth operating profit (loss) for each of Eni's business segments as a percentage of each segment's net sales from operations (including intragroup sales) for the periods presented.

	Year ended December 31,		
	2018	2017	2016
		(%)	
Exploration & Production	39.7	39.2	16.0
Gas & Power	1.1	0.1	(1.0)
Refining & Marketing and Chemicals	(1.5)	4.4	3.9
Group	**13.2**	**12.0**	**3.9**

Exploration & Production. In 2018, the Exploration & Production segment reported an operating profit of €10,214 million, with an increase of €2,563 million compared to the operating profit of €7,651 million reported in 2017. The better performance was driven by higher realized prices on equity hydrocarbons and production increases, with the latter boosted by the increased contribution of barrels with higher-than-average profitability.

The operating result of the Exploration & Production segment included the gain on the disposal of interests in the Shorouk and Nour concessions located offshore Egypt (€339 million, net of assignment bonus and other charges) and benefitted from the suspension for a semester of amortization charges at the held-for-sale subsidiary Eni Norge due to the pending business combination with Point Resources, which closed at year-end. Assets or disposal group held for sale are not to be depreciated or amortized in accordance to IFRS 5.

These positives were partly offset by an allowance for doubtful accounts as part of a dispute to recover credits for investments due by a State counterparty to align the recoverable amount with the expected outcome of an ongoing renegotiation (€158 million), environmental charges and a charge taken in connection with the outcome of an arbitration proceeding relating a long-term contract to purchase regasification services, which resulted in the termination of the contract and of the related annual fees charged to Eni. It also awarded the counterparty equitable compensation of €289 million. Finally, the result was negatively affected by currency translation effects being the EUR/USD dollar exchange rate up by 4.5% compared to 2017.

In 2018, the Company's liquids and gas realizations increased on average by 35.4% in dollar terms, driven by a strengthened petroleum environment. Eni's average oil realizations increased on average by 30.8%, in line with the increase recorded in international oil prices for the Brent market benchmark (up by 31% for the year). Eni's average gas realizations increased by 41% driven by the ramp-up of production with a higher-than-average sale price.

In 2017, the Exploration & Production segment reported an operating profit of €7,651 million, with an increase of €5,084 million compared to the operating profit of €2,567 million reported in 2016, due to an ongoing recovery in crude oil prices (the Brent benchmark in dollar terms was up by 24.2%; however, it was up by 21.7% in euro terms) and production growth. This result was also positively influenced by the net gains recorded on the disposal of a 40% interest in the Zohr asset (€1,281 million) and of a 25% interest in the exploration Area 4 offshore Mozambique (€1,985 million), the reversal of previously booked impairment losses at certain oil&gas CGUs driven by upward reserve revisions, updated projections of operating expenses and capital expenditures and the positive effect of the US tax reform. This gains were partially offset by impairment losses recorded at certain oil&gas projects in Venezuela and the related current trade receivables as discussed below, valuation allowances for doubtful accounts, as well as the recognition of losses on certain contractual and commercial disputes.

In 2017, the Company's liquids and gas realizations increased on average by 20.3% in dollar terms, driven by an increase in international oil prices for market benchmarks (Brent crude prices increased by 24.2%). Eni's average oil realizations increased on average by 27.8%. Eni's average gas realizations increased only by 12.8% because of time lags in oil-linked formulas.

In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the non-core gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of core business performance across reporting periods. Excluding the below-listed gains and charges, the E&P segment reported a Non-GAAP operating profit of €10,850 million, with an increase of €5,677 million from 2017, or 109.7%. The increase was driven by a recovery in the commodity environment which drove increased oil&gas realizations in dollar terms (up by 35.4% on average), production growth and an improved underlying performance driven by a better sales mix on the back of the growth of production with higher-than-average profitability.

Exploration & Production	Year ended December 31, 2018	2017	2016
	(€ million)		
GAAP operating profit (loss)	**10,214**	**7,651**	**2,567**
Net gains on disposal of assets	(442)	(3,269)	(2)
Impairment losses (impairment reversals), net	726	(158)	(677)
Environmental provisions	110	46	
Risk provisions	360	366	105
Reclassification of currency derivatives and translation effects to management measure of business performance	(6)	(68)	(3)
Valuation allowance of disputed receivables and others	158	442	410
Reinstatement of Eni Norge amortization charges	(375)		
Other	105	163	94
Total gains and charges	**636**	**(2,478)**	**(73)**
Non-GAAP operating profit (loss)	**10,850**	**5,173**	**2,494**

Gas & Power. In 2018, the Gas & Power segment reported an operating profit of €629 million, an increase of €554 million compared to the profit of €75 million of the previous year. This improvement was driven by the overall restructuring of all the business lines, effective management of flexibilities associated with the portfolio of long-term gas contracts, optimization in the power business and in logistics, as well as growth in the LNG business leveraging its integration with the E&P segment.

In 2017, the Gas & Power segment reported an operating profit of €75 million, improving by €466 million compared to 2016 when the segment reported an operating loss of €391 million. This result was driven by the economic benefits from the renegotiation of gas supply contracts as well as lower logistic costs and improved performance in trading, LNG and Power businesses. Result also includes the reversal of asset impairment losses recorded in previous reporting periods for €146 million, mainly relating to the alignment of the book value of the Hungarian gas distribution activity to its fair value, in light of a sale negotiation ongoing at the balance sheet date which may lead to a sale being completed in 2018.

Furthermore, from 2017, the profit/loss on stock has been included in the business underlying performance due to a changed regulatory framework on gas storage in Italy, on which basis management has elected to leverage gas stocks as a way to improve margins.

These positives were partly offset by lower gains in connection with the effects of fair-valued commodity derivatives that lacked the formal criteria to be accounted as hedges under IFRS.

In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods.

Excluding the below-listed gains and charges, the G&P segment reported a Non-GAAP operating profit of €543 million, with an increase of €329 million from 2017, reflecting the strong progress in restructuring all business lines. The main drivers of the operational improvements were the growth in LNG sales and margins as well as power and logistic optimizations. Furthermore, the favorable trends registered in the first nine months in the natural gas wholesale market enabled the Company to extract value from the flexibilities associated with the portfolio of long-term supply contracts, such as the opportunity to sell additional volumes beyond the minimum take at long-term contracts in case of favorable demand trends like those that occurred during the first nine months thanks to a tight gas market (i.e. the flexibility associated with the possibility to lift additional gas volumes from a long-term contract once the minimum annual take has been fulfilled up to the annual contractual quantity). Also the retail business showed an improved performance driven by lower credit losses due to the initiatives designed to de-risk the customer portfolio, as well as efficiency gains.

The items excluded from GAAP operating profit in determining the Non-GAAP measure of profitability include certain commodity fair-valued derivatives and accruals measurements.

Particularly, we enter into commodity and currency derivatives to reduce our exposure to (i) the commodity risk due to different indexation between the purchase cost and the selling price of gas and power or to lock in a commercial margin once a sale contract has been signed or it is highly probable, and

(ii) the underlying exchange rate risk due to the fact that our selling prices are indexed to the euro and our supply costs are denominated in dollars. These derivatives normally hedge net Group exposure to commodities and exchange rates but do not meet the requirements for being accounted as hedges in accordance to IFRS.

Therefore, in explaining year-on-year charges and in evaluating the business performance management believes that is appropriate to identify the fair value of commodity derivatives because they relate to transactions that will close in subsequent reporting periods or we estimate the portion of gains and losses on the settlement of certain commodity derivatives where underlying physical transaction has yet to be settled with the delivery of the underlying commodity. Furthermore, although the Group classifies within net finance expense those gains and losses on currency derivatives, as well as on the alignment of trade receivable and payables denominated in dollars into the accounts of euro subsidiaries at the closing rate, we believe that it is appropriate to consider those gains and losses on currency derivatives and currency differences at our dollar-denominated trade payables and receivables as part of the underlying business performance.

From 2017, the recognition of the inventory holding (gains) losses has been discontinued in the Gas & Power segment adjusted result considering that inventory levels have been minimized and the fact that management is leveraging inventories to improve margins.

	Year ended December 31,		
	2018	2017	2016
Gas & Power		(€ million)	
GAAP operating profit (loss)	**629**	**75**	**(391)**
(Profit) loss on inventory			90
Impairment losses (impairment reversals), net	(71)	(146)	81
Environmental provisions	(1)		
Allowance for doubtful accruals in the retail G&P			17
Provision for redundancy incentives	122	38	4
Fair value gains/losses on commodity derivatives	(156)	157	(443)
Reclassification of currency derivatives and translation effects to management measure of business performance	112	(171)	(19)
Estimated revenues accruals in the retail G&P		64	161
Revision of estimated revenues accruals in the retail G&P (difference between incurred loss vs. expected loss model)		223	
Other	(92)	(26)	110
Total gains and charges	**(86)**	**139**	**1**
Non-GAAP operating profit (loss)	**543**	**214**	**(390)**

Refining & Marketing. In 2018, the Refining & Marketing and Chemicals segment reported an operating loss of €380 million, reversing the operating profit of €981 million reported in 2017, driven by a challenging trading environment because of rapidly-escalating oil-based feedstock costs which were not fully recovered in the final prices of products due to competitive pressure from more efficient producers and a slowdown in end-markets, leading to a squeeze in margins.

Furthermore, due to a sharp decline in crude oil and products prices recorded in the final weeks of 2018, inventories were aligned to their net realizable values recording an estimated loss of €234 million compared to an inventory profit of €213 million a year ago. Impairment losses and environmental provisions negatively affected the reported results by approximately €250 million.

The refining activity was negatively affected by a 26% decline in refining margins and by longer plant standstills. The oxygenated business was penalized by downtime at certain assets due to prolonged maintenance activities. These negative trends were offset by plant and supply optimizations, as well as by higher margins on green throughputs. Marketing activities reported an improved performance both in the retail and wholesale segments also leveraging on effective commercial initiatives to support margins and on efficiency actions.

The Chemical business was affected by the worsening trading environment characterized by sharply higher supply costs of oil-based feedstock in the first ten months that were not recovered in sale prices, by competitive pressures and by a demand slowdown in the last part of the year, mainly in the polyethylene segment, which resulted in a strong contraction of the benchmark margin of cracker (down by 11%) and polyethylene margins (down by 69%), as well as, by the fact that the first half of 2017 benefitted from particularly high prices of intermediates (butadiene and benzene) due to contingent factors.

In 2017, the Refining & Marketing and Chemicals segment reported an operating profit of €981 million, with an improvement of €258 million y-o-y, driven by higher refining margins, particularly in the nine months of the year, and which also benefitted from the restructuring of Eni refineries and petrochemicals hubs implemented over the latest years. Refinery optimization helped Eni to reduce the break-even margin below the 4 $/BBL threshold and capture the upside in the scenario recorded in the first nine months of 2017. Operating profit included also the gain from the licensing of the EST conversion technology to Sinopec. These positives were partly offset by lower plant availability at the Sannazzaro refinery in connection with the shutdown of the EST unit, which is undergoing a rebuilding. The marketing business performed well due to effective commercial initiatives, mainly in the segment of premium products and services.

In the Chemical business, the optimized plant setup at core hubs and the focus of the product portfolio towards higher-value segments enabled the company to leverage the upside in the trading environment and to achieve volume upsides.

Better industrial trends were partly offset by a lower inventory gain.

The main item excluded from GAAP operating profit in determining the Non-GAAP measure of profitability is the inventory holding gain (or loss). Inventory holding gains or losses represent the difference between the cost of sales of the volumes sold during the period calculated using the cost of supplies incurred during the same period and the cost of sales calculated using the weighted average cost method. Under the weighted average cost method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historic cost of purchase, or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant impact on reported income thereby affecting comparability. The amounts disclosed represent the difference between the charge (to the income statement) for inventory on a weighted average cost method basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a quarterly or monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions. We regard the inventory holding gain or loss, including any write-down to align the carrying amounts of inventories to their net realizable value at the reporting date, as lacking correlation to the underlying business performance which we track by matching revenues with current costs of supplies.

In addition to the inventory holding loss, the non-core items of this segment for the year 2018 also comprised the write down of capital expenditures relating to certain Cash Generating Units in the refining business, which were impaired in previous reporting periods and continued to lack any profitability prospects (€156 million) and environmental provisions (€165 million).

In reviewing the performance of the Company's business segments and with a view to better explaining year-on-year changes in the segment performance, management generally excludes the inventory holding gain (or loss) and the other non-core gains and losses presented below in order to assess the underlying industrial trends and obtain a better comparison of base business performance across reporting periods. Excluding the below-listed gains and charges, the R&M and Chemical segment reported a Non-GAAP operating profit of €380 million, with a decrease of €611 million from 2017 due to the industrial trends described above.

Refining & Marketing and Chemicals	Year ended December 31, 2018	2017	2016
		(€ million)	
GAAP operating profit (loss)	**(380)**	**981**	**723**
(Profit) loss on inventory	234	(213)	(406)
Environmental provisions ond other costs	243	136	104
Impairment losses (impairment reversals), net	193	54	104
Net gains on disposal of assets	(9)	(13)	(8)
Provision for redundancy incentives	8	(6)	12
Other	91	52	54
Total gains and charges	**760**	**10**	**(140)**
Non-GAAP operating profit (loss)	**380**	**991**	**583**

Corporate and Other activities. These activities are mainly cost centers comprising holdings, financing and treasury activities in support of operating subsidiaries, central functions like information technology, legal counselling, human resources, insurance activitiesm general and administrative support, as well as the Group environmental clean-up and remediation activities performed by the subsidiary Syndial.

The aggregate Corporate and Other activities reported an operating loss of €691 million in 2018, an increase of €23 million from 2017, or 3.4%.

The aggregate Corporate and Other activities reported an operating loss of €668 million in 2017 representing an increase of €13 million from 2016, or 1.9%, mainly reflecting the recognition of risk provisions related to environmental issues and other, that were partly offset by the implementation of cost efficiency measures.

e) Net finance expenses

The table below sets forth a breakdown of Eni's net financial expenses for the periods indicated:

	Year ended December 31, 2018	2017	2016
		(€ million)	
Gain (loss) on derivative financial instruments	(307)	837	(482)
of which – Derivatives on exchange rate	*(329)*	*809*	*(494)*
– Derivatives on interest rate	*22*	*28*	*(12)*
Exchange differences, net	341	(905)	676
Net income from financial activities held for trading	32	(111)	(21)
Interest income due to banks	18	12	15
Finance expense from banks on short and long-term debt	(685)	(751)	(757)
Finance expense due to the passage of time (accretion discount)	(249)	(264)	(312)
Other finance income and expense, net	(173)	(127)	(110)
	(1,023)	**(1,309)**	**(991)**
Finance expense capitalized	52	73	106
NET FINANCE EXPENSES	**(971)**	**(1,236)**	**(885)**

2018 compared to 2017. In 2018, net finance expenses were €971 million, lower by €265 million than in 2017. This reduction was due to lower interest expense on short and long-term debt, which reflected the €2,627 million decrease in net borrowings. Like in the comparative periods, losses on exchange rate derivatives were offset by gains on currency translation at dollar-denominated payables and receivables accrued by Italian subsidiaries, as the Group normally pools different exposures to the currency risk retained by operating subsidiaries and then hedges the Group net exposure to the risk.

Other net finance income and expense were a loss of €173 million driven by the impairment of operating financing receivables due by an equity-accounted entity, which engaged in the execution of an exploration projects that was written-off due to an unsuccessful outcome.

2017 compared to 2016. In 2017, net finance expenses were €1,236 million, down by €351 million compared to 2016 reflecting the recording of currency losses partly offset by positive fair value adjustments on currency derivatives (for a net negative effect of €278 million), with the latter lacking the formal criteria to be designated as hedges under IFRS. Furthermore, a loss from financial activities held for trading (€111 million) was recorded due to the translation differences, which were offset by a corresponding gain on exchange derivatives that did not satisfy the criteria for hedge accounting. Other net finance income and expense, referred to the impairment of operating financing receivables.

f) Net income from investments

2018 compared to 2017. In 2018 the Group reported a net profit from investments of €1,095 million and related to:

i). dividends of €231 million paid by minor investments in certain entities which were designated at fair value through OCI under IFRS 9 except for dividends which are recorded through profit. These entities mainly comprised Nigeria LNG Ltd (€187 million, where Eni has an interest of 10.4%) and Saudi European Petrochemical Co (€35 million, where Eni has an interest of 10%);

ii). other net gains (€910 million) including the net gain on the Vår Energi business combination (approximately €890 million);

iii). the impairment reversal (€262 million) at the Angola LNG equity-accounted entity due to improved project economics.

These gains were partly offset by Eni's share of losses incurred by equity-accounted investments (€430 million) driven by losses recorded by the Saipem joint venture due mainly to the incurrence of impairment losses and restructuring charges by the investee, and by an impairment loss of a joint venture which engaged in an oil project due to the downward reserve revision on the back of a deteriorated operating environment.

2017 compared to 2016. In 2017 the Group reported a net profit from investments of €68 million related to:

i). dividends received from entities accounted for at cost (€205 million) relating to Nigeria LNG Ltd (€167 million) and Saudi European Petrochemical Co (€21 million);

ii). net gains on the divestment of interests (€163 million) mainly relating to the disposal of the Gas & Power retail activity in Belgium.

These positives were partly offset by:

i). a loss of €267 million recorded on equity-accounted entities, mainly in the E&P segment (€99 million) and in the Chemical business (€61 million). This also included a loss of €101 million recorded on the equity-accounted interest retained in Saipem, which was driven by the recognition of asset impairment charges and other extraordinary expenses by the investee;

ii). other net losses mainly relating to an impairment charge recorded in the G&P segment referred to the interest in Unión Fenosa Gas SA (€35 million) due to a reduced profitability outlook.

g) Taxes

2018 compared to 2017. In 2018, income taxes amounted to €5,970 million, up by €2,503 million compared to 2017, or 72,2%. This increase reflected higher income before taxes which was €10,107 million, almost doubling compared to 2017.

Tax rate was approximately 59% compared to 51% reported in 2017, reflecting lower gains free of taxes or subject to a lower tax rate compared to the Group average tax rate. Excluding those non-core effects the Group tax rate was substantially in line with 2017 due to higher contribution of segments other than the E&P, the effect of which offset the increased E&P tax rate due to the recognition of lower deferred tax assets on projects and the fact that the loss incurred at an equity-accounted exploration project was not deductible.

2017 compared to 2016. In 2017, income taxes amounted to €3,467 million, up by €1,531 million compared to 2016, or 79%. This increase reflected higher income before taxes which was up by €5,952 million compared to 2016.

Tax rate was 51% compared to 217% recorded in 2016. This trend was explained by a recovery in profit before taxes at the E&P segment which helped the Company offset against the taxable income a higher share of deductible expenses, including those incurred under PSA contracts, and to dilute the incidence of non-deductible expenses. The reduction also reflected the recognition of deferred taxes in connection with the FID of the Coral project in Mozambique and the production start-up in Ghana.

Taxes included the tax effects relating to operating special items, the write-off of deferred tax asset of subsidiaries in the USA following the recognition of the effect of the newly enacted tax regime (€115 million), offset by the recognition of higher deferred tax asset at Versalis driven by the projection of improving future taxable earnings.

Liquidity and capital resources

Eni's cash requirements for working capital, dividends to shareholders, capital expenditures and acquisitions over the past three years were financed primarily by a combination of funds generated from operations, borrowings and divestments of minority interests in certain of our exploration assets and other non-strategic activities. The Group continually monitors the balance between cash flow from operating activities and net expenditures targeting a sound and balanced financing structure.

The following table summarizes the Group cash flows and the principal components of Eni's change in cash and cash equivalent for the periods indicated.

	Year ended December 31,		
	2018	**2017**	**2016**
		(€ million)	
Net profit (loss)	**4,137**	**3,377**	**(1,044)**
Adjustments to reconcile net profit to net cash provided by operating activities:			
– amortization and depreciation charges, impairment losses, write-off and other non monetary items	7,657	8,720	7,773
– net gains on disposal of assets	(474)	(3,446)	(48)
– dividends, interest, taxes and other changes	6,168	3,650	2,229
Changes in working capital related to operations	1,632	1,440	2,112
Dividends received, taxes paid, interest (paid)	(5,473)	(3,624)	(3,349)
Net cash provided by operating activities	**13,647**	**10,117**	**7,673**
Capital expenditures	**(9,119)**	**(8,681)**	**(9,180)**
Acquisition of investments and businesses	(244)	(510)	(1,164)
Disposals of consolidated subsidiaries, businesses, tangible and intagible assets and investments	1,242	5,455	1,054
Other cash flow related to investing activities (*) (**)	585	(32)	5,736
Changes in short and long-term finance debt	320	(1,712)	(766)
Dividends paid and changes in non-controlling interests and reserves	(2,957)	(2,883)	(2,885)
Effect of changes in consolidation, exchange differences and cash and cash equivalents	18	(65)	(3)
Change in cash and cash equivalent for the year	**3,492**	**1,689**	**465**
Cash and cash equivalent at the beginning of the year	7,363	5,674	5,209
Cash and cash equivalent at year end	10,855	7,363	5,674

(*) For 2016, the item also includes the reimbursement of intercompany financing loans owed to Eni by Saipem for € 5,818 million.

(**) Net cash used in investing activities included investments in and divestments of certain financial assets (mainly bank deposits) to absorb temporary surpluses of cash or as part of our ordinary management of financing activities. Due to their nature and the circumstance that they are very liquid, these financial assets are netted against finance debt in determining net borrowings. Furthermore, due to the Company's decision to retain a cash reserve composed of held-for-trading securities, net cash used in investing activities also included investments and divestments of those securities. Also these held-for-trading financial assets are netted against finance debt in determining the Group net borrowings. For more information on their composition see Note 6 to the Consolidated Financial Statements. For the definition of net borrowings, see "Financial Condition" below. Cash flows of such investing activity were as follows:

(€ million)	**2018**	**2017**	**2016**
Investing activity:			
– securities	(424)	(316)	(1,317)
– financing receivables	(196)	(72)	(272)
	(620)	**(388)**	**(1,589)**

(€ million)	2018	2017	2016
Disposal:			
– securities	46	223	
– financing receivables	217	506	6,860
	263	**729**	**6,860**
Net cash flows used in investing activity	**(357)**	**341**	**5,271**

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
Net cash provided by operating activities	**13,647**	**10,117**	**7,673**
Capital expenditures	(9,119)	(8,681)	(9,180)
Acquisitions of investments and businesses	(244)	(510)	(1,164)
Disposals of consolidated subsidiaries, businesses, tangible and intangible assets and investments	1,242	5,455	1,054
Other cash flow related to capital expenditures, investments and divestments	942	(373)	465
Net borrowings[(1)] of acquired companies	(18)		
Net borrowings[(1)] of divested companies	(499)	261	5,848
Exchange differences on net borrowings and other changes	(367)	474	284
Dividends paid and changes in minority interest and reserves	(2,957)	(2,883)	(2,885)
Change in net borrowings[(1)]	**2,627**	**3,860**	**2,095**
Net borrowings[(1)] at the beginning of the year	10,916	14,776	16,871
Net borrowings[(1)] at year end	8,289	10,916	14,776

(1) Net borrowings is a non-GAAP financial measure. For a discussion of the usefulness of net borrowings and its reconciliation with the most directly comparable GAAP financial measures see "Financial Condition" below.

Analysis of the line items of the profit and loss account

In 2018, adjustments to reconcile net profit to net cash provided by operating activities mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization, impairment charges and reversals and the write-off of tangible and intangible assets (€7,954 million) and gains on disposals (€474 million). Adjustments to net profit also included accrued income taxes (€5,970 million) and interest expense (€614 million), which were partly offset by amounts actually paid (€5,226 million and €609 million, respectively).

In 2017, adjustments to reconcile net profit to net cash provided by operating activities mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization, impairment charges and reversals and the write-off of tangible and intangible assets (€7,521 million) and gains on disposals (€3,446 million). Adjustments to net profit also included accrued income taxes (€3,467 million) and interest expense (€671 million), which were more than offset by amounts actually paid (€3,437 million and €582 million, respectively). Net profit was negatively impacted by extraordinary credit losses amounting to €616 million which included the recognition of a valuation allowance for doubtful accounts in the E&P business and in the retail G&P business. Taxes paid included an extraordinary payment made for a tax settlement in Angola (€150 million) relating to past reporting periods.

a) Changes in working capital related to operations

In 2018, working capital generated an inflow of €1,632 million. This was mainly due to a positive balance between trade receivables collected and trade payables paid (a net inflow of €976 million), mainly in the Gas&Power segment and because we collected advances on future supplies of equity gas to our state-owned partners in Egypt in implementation of the agreements designed to provide adequate funding to the reserves development projects ongoing in the Country (€280 million). Other positive working capital adjustments for approximately €0.47 billion related to a risk provisions to settle an arbitration ruling and a positive adjustment relating to an allowance for credit losses in the E&P segment.

In 2017, working capital generated an inflow of €1,440 million. This was mainly due to a positive balance between trade receivables collected and trade payables paid (a net inflow of €941 million) which reflected the higher volume of trade receivables due subsequently to the reporting date which were sold to financing institutions compared to the previous reporting period (about €282 million) and also the adjustment in connection with the allowance for doubtful accounts in the retail Gas & Power segment.

Finally, other positive working capital adjustments related risk provisions and a positive adjustment relating the item other current assets and liabilities (up by €749 million) which mainly reflected the impairment of receivables in the E&P segment and a change in the derivatives fair value.

b) Investing activities

	Year ended December 31,		
	2018	2017	2016
		(€ million)	
Exploration & Production	7,901	7,739	8,254
Gas & Power	215	142	120
Refining & Marketing and Chemicals	877	729	664
Corporate and other activities	143	87	55
Impact of unrealized intragroup profit elimination	(17)	(16)	87
Capital expenditures	**9,119**	**8,681**	**9,180**
Acquisitions of investments and businesses	**244**	**510**	**1,164**
	9,363	**9,191**	**10,344**
Disposals of consolidated subsidiaries, businesses, tangible and intangible assets and investments	**(1,242)**	**(5,455)**	**(1,054)**

Capital expenditures totaled €9,119 million and €8,981 million, respectively in 2018 and in 2017.

For a discussion of capital expenditures by business segment and a description of year-on-year changes see below "Capital expenditures by segment".

Acquisition of investments and businesses totaled €244 million in 2018 and €510 million in 2017. In 2018, acquisition of investments mainly related to (i) the subscription of a share capital increase at the Coral FLNG SA (€48 million) which is engaged in the development of a floating production and storage unit of LNG in natural gas-rich Area 4 offshore Mozambique; (ii) the 33.72% interest in the Commonwealth Fusion System Llc (CFS) which was set up following the spin-out of the Massachusetts Institute of Technology engaged in the development of technology for the production of nuclear fusion power; (iii) the acquisition of activities and technologies of in the segment of green chemicals based on use of renewable resources, particularly biomass; as well as (iv) the residual interest of the Gas Supply Company Thessaloniki Thessalia SA, involved in the distribution and marketing of natural gas in Greece (€24 million).

In 2018, disposals amounted to €1,242 million and mainly related to: (i) the divestment of a 10% interest in the Zohr field in Egypt to Mubadala Petroleum; (ii) the sale of the consolidated subsidiaries Tigáz Zrt and Tigáz Dso engaged in the gas distribution activity in Hungary; (iii) the sale of Eni's share in the gas and liquid field in Sanga Sanga; (iv) the divestment of 100% interest of the fully consolidated Eni Croatia BV and of Eni Trinidad and Tobago Ltd. These cash inflows were netted by the cash of Eni Norge disposed of due to the business combination with Point Resources which led to the loss of control over the subsidiary (€258 million).

In 2017, disposals amounted to €5,455 million and mainly related to: (i) the sale to ExxonMobil of a 25% interest in natural gas-rich Area 4 offshore Mozambique where development activities are ongoing to put into production the significant gas resources discovered by Eni. The net cash consideration amounted to €2,061 million including the corresponding portion of net borrowings of the business divested to the buyer amounting to €264 million; (ii) the sale of a 40% stake in the Zohr project located in Egypt sold to BP and Rosneft (€2,526 million); (iii) the sale of the whole interest in the consolidated company Eni Gas & Power NV and its subsidiary Eni Wind Belgium NV, operating in the gas & power retail activities in Belgium. The sale price amounted to €302 million including cash divested of €8 million.

b) Dividends paid and changes in non-controlling interests and reserves

In 2018, dividends paid and changes in non-controlling interests and reserves (€2,957 million) related almost exclusively to Eni shareholders (€2,954 million, of which €1,513 million relating to the 2018 interim dividend and €1,441 million to the final dividend for fiscal year 2017).

In 2017, dividends paid and changes in non-controlling interests and reserves (€2,883 million) related almost exclusively to cash dividends to Eni shareholders (€2,880 million, of which €1,440 million relating to the 2017 interim dividend and €1,440 million to the final dividend for fiscal year 2016).

Financial condition

Management assesses the Group's capital structure and capital condition by tracking net borrowings, which is a non-GAAP financial measure. Eni calculates net borrowings as total finance debt (short-term and long-term debt) derived from its Consolidated Financial Statements prepared in accordance with IFRS less: cash, cash equivalents and certain highly liquid investments not related to operations including, among others, a liquidity reserve made of held-for-trading securities and finally other liquid assets not related to operations (financing receivables and securities). The Company is retaining a liquidity reserve, which comprises very liquid investments, mainly sovereign and corporate securities which management has selected based on their creditworthiness. This cash reserve was established by investing part of the proceeds from the disposal plan carried out in the latest years.

Those securities amounted to €6,552 million as of end of 2018 and were accounted as mark-to-market financial instruments. For further information, see "Item 18 – Note 6 – Financial assets held for trading – of the Notes on Consolidated Financial Statements". Non-operating financing receivables consist mainly of deposits with banks and other financing institutions and deposits in escrow.

Management believes that net borrowings is a useful measure of Eni's financial condition as it provides insight about the soundness of Eni's capital structure and the ways in which Eni's operating assets are financed. In addition, management utilizes the ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage) to assess Eni's capital structure, to analyze whether the ratio between finance debt and shareholders' equity is well balanced compared to industry standards and to track management's short-term and medium-term targets. Management continuously monitors trends in net borrowings and trends in leverage in order to optimize the use of internally-generated funds versus funds from third parties. The measure calculated in accordance with IFRS that is most directly comparable to net borrowings is total debt (short-term and long-term debt). The most directly comparable measure, derived from IFRS reported amounts, to leverage is the ratio of total debt to shareholders' equity (including non-controlling interest). Eni's presentation and calculation of net borrowings and leverage may not be comparable to other companies.

The tables below set forth the calculations of net borrowings and leverage for the periods indicated and their reconciliation to the most directly comparable GAAP measure.

	As of December 31,					
	2018			2017		
	Short-term	Long-term	Total	Short-term	Long-term	Total
Finance debt (short-term and long-term debt)	**5,783**	**20,082**	**25,865**	**4,528**	**20,179**	**24,707**
Cash and cash equivalents	(10,836)		**(10,836)**	(7,363)		**(7,363)**
Securities held for trading and other securities held for non operating purposes	(6,552)		**(6,552)**	(6,219)		**(6,219)**
Non operating financing receivables	(188)		**(188)**	(209)		**(209)**
Net borrowings	**(11,793)**	**20,082**	**8,289**	**(9,263)**	**20,179**	**10,916**

		As of December 31,	
		2018	2017
Shareholders' equity including non-controlling interest as per Eni's Consolidated Financial Statements prepared in accordance with IFRS	(€ million)	**51,073**	**48,079**
Ratio of finance debt to total shareholders' equity including non-controlling interest		*0.51*	*0.51*
Less: ratio of cash, cash equivalents and certain liquid investments not related to operations to total shareholders' equity including non-controlling interest		*(0.34)*	*(0.29)*
Ratio of net borrowing to total shareholders' equity including non-controlling interest (leverage)		*0.16*	*0.23*

Total debt of €25,865 million consisted of €5,783 million of short-term debt (including the portion of long-term debt due within twelve months equal to €3,601 million) and €20,082 million of long-term debt.

Total debt included unsecured bonds for €19,704 million (including accrued interest and discount on issuance). Bonds maturing in the next 18 months amounted to €4,596 million (including accrued interest and discount). Bonds issued in 2018 amounted to €2,844 million (including accrued interest and discount). Total debt was denominated in the following currencies: euro (75%), U.S. dollar (21%) and 4% in other currencies.

In 2018, net borrowings amounted to €8,289 million, representing a €2,627 million decrease from 2017. This reduction was driven by net cash flow from operations amounting to €13,647 million, the disposal of a 10% interest in Zohr in Egypt and of other non-strategic assets for a total of €1.24 billion and other cash inflows related to investing activities, particularly the collection of two price instalments related to the disposal of interests of 10% and 30% in the Zohr project executed in 2017. As at December 31, 2018 securities held for trading included €5.5 billion of corporate bonds.

The ratio of finance debt to total equity was 0.51 at 2018 year-end.

Total equity increased by €2,994 million from December 31, 2017. This was due to the profit for the year, the positive foreign currency translation differences (€1,787 million) due to a 4.5% appreciation of the euro against the US dollar at year end (the exchange rate recorded on December 31, 2018 at 1.146, compared to 1 euro = 1.202 euro US$ at December 31, 2017), partly offset by dividend distribution of €2,953 million.

The Group Non-GAAP measure of its financial condition "Leverage" was 0.16 at December 31, 2018 reporting a decrease from 0.23 as of the end of 2017. This decline was driven by lower net borrowing, the effects of which were partly offset by an increase in the Group total equity as explained below.

Capital expenditures by segment

Exploration & Production. In 2018, capital expenditures of the Exploration & Production segment amounted to €7,901 million, mainly related to the development of oil&gas reserves (€6,506 million). Significant expenditures were directed mainly outside Italy, in particular in Egypt, Ghana, Norway, Libya, Nigeria, Congo and Iraq. Exploration expenditures (€463 million) were directed in particular in United States, Egypt, Mexico, United Arab Emirates and Indonesia.

In the 2018, the total amount of €869 million related to the purchase of proved and unproved reserves and included the entry bonus in two producing concessions and in the offshore Ghasha concession in the United Arab Emirates.

Gas & Power. In 2018, capital expenditures in the Gas & Power segment totaled €215 million and mainly related to gas marketing initiatives (€161 million)) due to the purchase of interests in local gas distributors in markets synergic to our core operations and to the capitalization of expenses for the acquisition of new customers, and to the business of power generation (€46 million).

Refining & Marketing and Chemicals. In 2018, capital expenditures in the Refining & Marketing and Chemicals segment amounted to €877 million and regarded mainly: (i) refining activity in Italy and outside Italy (€587 million) aiming fundamentally at reconstruction works of the EST conversion plant at the Sannazzaro refinery, maintain plants' integrity, as well as initiatives in the field of health, security and environment; (ii) marketing activity, mainly regulation compliance and stay in business initiatives in the refined product retail network in Italy and in the Rest of Europe (€139 million); (iii) upgrading activities (€52 million); maintenance (€32 million), as well as environmental protection, safety and environmental regulation (€26 million) in the Chemicals business (€151 million).

Recent developments

The table below sets forth certain indicators of the trading environment for the periods indicated:

	Three months ended March 31, 2018	Three months ended March 31, 2019
Average price of Brent dated crude oil in U.S. dollars(1)	67	63
Average EUR/USD exchange rate(2)	1.229	1.136
Standard Eni Refining Margin (SERM)(3)	3.0	3.4

(1) Price per barrel. Source: Platt's Oilgram.
(2) Source: ECB.
(3) In $/BBL, FOB Mediterranean Brent dated crude oil. Source: Eni calculations. Approximates the margin of Eni's refining system in consideration of material balances and refineries' product yields.

In the period January 1 – March 31, 2019 the Brent crude oil price was 63 $/BBL on average, 6% lower than in the first quarter of 2018. This trend will negatively affect reported revenues, profitability and cash flow of our Exploration & Production segment, partly offset by the depreciation of the EUR vs. the USD.

Significant transactions

The significant transactions that occurred post-closing are described in item 4.

Management's expectations of operations

Exploration & Production

Management will seek to boost the cash generation in the E&P segment leveraging on profitable production growth, capital discipline, effective project execution and strict control of operating expenses and working capital.

Exploration will continue driving the Company's growth in the short and long-term. In the next four years, our exploration activities will focus on supporting the replacement of produced reserves and on contributing to cash generation. Our priorities in exploration will be:

- Near-field success; i.e. the discovery of reserves in prospects close to producing fields, where we can leverage on existing infrastructures to readily develop the discovered resources, ensuring fast contribution to cash flows;
- Initiatives in operated licenses with high working interest targeting conventional resources, where in case of material discoveries we can apply our dual exploration model;
- A resumption of activities in high-risk, high-rewards plays.

Our dual exploration model contemplates the acquisition of high interests in exploration leases and, in case of exploration success, the partial divestiture of the discovered resources with a view of accelerating the conversion of resources into cash or of accomplishing asset swaps.

We are targeting a 3.5% average growth rate in hydrocarbons production up to a plateau of 2.13 million boe/d in the 2019-2022 plan period. In 2019, we expect a production growth of approximately 2.5% at constant Brent prices and excluding the effects of portfolio transactions. This growth is expected to be fueled organically by new fields start-ups and the achievement of full-field production at our main producing fields, including the Zohr gas field in Egypt, Block 15/06 in Angola and the gas project offshore Ghana, as well as continuing production optimization to fight fields natural decline. The main start-ups expected in the plan period include the projects that were sanctioned in 2018, mainly the Area 1 oil project offshore Mexico, the Merakes gas field in Indonesia, phase two of the Nenè Marine field in Congo and other developments in Italy, Egypt and Angola. We estimate that new field start-ups and production ramp-ups will add approximately 660 KBOE/d in 2022. We have good visibility as to the ability to achieve those production targets because they relate to already-sanctioned projects, mostly of which are operated, and to incremental development phases at our existing profit centers. Finally, in 2022 we are planning to start up production at certain very large projects in Mozambique, UAE, Norway and Nigeria which will contribute to our long-term production growth.

Our production plans include assumptions relating to production levels in certain countries that are particularly exposed to risks of disruptions and political instability. To factor in possible risks of unfavorable geopolitical developments in those countries, which may lead to temporary production losses and disruptions in our operations in connection with, among others, acts of war, sabotage, social unrest, clashes and other form of civil disorder, we have applied a haircut to our future production levels based on management's appreciation of those risks, past experience and other considerations. However, this contingency factor does not cover worst-case developments and extreme events, which could determine prolonged production shutdowns. We note that our strategy of diversifying the geographic reach of our operations will lessen going forward our dependence on less politically stable areas such as North Africa, where we expect to reduce the relative weight of our production.

Our production plans are incorporating our Brent price scenario of 62 $/BBL in 2019 and a gradual ramping in the subsequent years up to our long-term case of 70 $/BBL in 2022 and going forwards (on constant monetary term 2022, i.e. from 2023 onwards crude oil prices will grow in line with a projected inflationary rate). Our pricing assumptions are based on forecast of steady oil demand growth against the backdrop of a moderate pace of expansion in the global economy and continuing support from Opec members and other producing countries to maintain a balance between global oil demand and supplies. We also expect that international oil companies will retain a disciplined approach to capital spending going forward. There are some risks to this outlook, including the role of OPEC and its ability to control global prices, the ability on the part of unconventional oil producers in the US to remain competitive in the current scenario and to continue increasing well productivity, as well as the role of geopolitical factors and any possible developments in the USA-China trade war and in Brexit. We note that following the sharp correction registered in the final months of 2018, crude oil prices have currently stabilized around the level of 62 – 63 $ per barrel in the first quarter of 2019 and volatility has subdued.

Due to those risks and uncertainties, management intends to retain a strong focus on capital and cost discipline and on reducing the time-to-market of our reserves. First, our capital projects will be carefully selected against our scenario assumptions and minimum requirements of internal rates of return. We intend to reduce financial exposure leveraging on a phased approach in developing our projects. Secondly, we plan to deliver our planned projects on time and on budget. Several of our projects are complex due to scale and reach of operations, environmentally-sensitive locations, external conditions, including offshore operations, industry limits and other considerations including the risk factors described in Item 3. These constraints and factors might cause delays and cost overruns. We plan to mitigate those risks in the future by continuing deployment of our skills and by our model of project execution driven by: (i) the execution in parallel of the main project activities, including discovery appraisal and pre-fid activities; (ii) the in-sourcing of critical engineering and project management phases, for example we are exercising strict control over hook-up and commissioning; (iii) the design-to-cost method whereby the Company has redirected its exploration efforts towards mature and low-complexity areas where we can achieve fast time-to-market and cost synergies; (iv) continuing progress in our technologies designed to improve drilling performance and the recovery factor.

Phased project development and strict integration between exploration and development have improved the overall project execution and cost efficiency. Finally, all of our projects undergo a thorough HSE assessment leading to the definition of an integrated plan to reduce blow-out and other well and operational risks and costs. Due to those drivers and our estimation that in recent years our discovery costs have been efficient, we believe that the price breakeven of our ongoing projects has decreased over the latest years, thus reducing the risk of a volatile scenario.

Finally, we plan to seek opportunities for further reductions in our development and operating costs, for example by reducing the downtime at our facilities and other measures.

Management also plans to increase the share of operated production in the Company's portfolio. We expect operated production to grow at a faster rate than the average production leading to increase to 75% the rate of operated production at the end of the plan vs the current 73%. Project operatorship enables the Company to better schedule and control project execution, expenditures and timely achievement of project milestones and to mitigate project risks.

Gas & Power

We expect a weak outlook in the Gas & Power segment due to structural headwinds in the industry as we forecast sluggish demand growth, oversupplies and strong competition across all of our main markets in Europe, including Italy. Demand growth will be dampened by rising competition from renewables, increasing energy efficiency and an ongoing slowdown in the European economies. We are assuming that after a temporary reduction in supplies due to growing Asian demand and a slowdown in new project-sanctioning during the downturn, LNG supplies will resume adding pressures to the European markets based on expectations of a cooling off in demand from Far East and the coming online of new capacity. LNG cargoes are also expected to be delivered at Italian re-gasification terminals. Finally, new import gas pipelines to European markets are under consideration, which could possibly add to the risks of an oversupplied market. These trends are expected to be exacerbated by the constraints of the long-term supply contracts with take-or-pay clauses, whereby wholesale operators are forced to compete aggressively on pricing in order to limit the financial exposure dictated by the contracts in case of volumes off-taken below the minimum take. These developments are expected to increase market liquidity and to put pressure on the spread between gas spot prices at hubs in the northern Europe, which are the main indexation parameter of our supply contracts, and prices at the spot market in Italy which is the main market to sell our procured gas. Particularly, we expect the spread to decline by the end of the plan period when a new import route to Italy via pipe is anticipated to start operations.

Against this scenario, the Company priority in its Gas & Power business is to strengthen profitability and cash generation. The main drivers to achieve these goals are:

(i) the renegotiations of our long-term gas supply contracts to align pricing and volume terms to current market conditions and dynamics as they evolve, and the reduction of logistic costs;
(ii) the development of the LNG marketing business leveraging on the integration with the E&P segment with the aim of maximizing the profitability along the entire gas value-chain and of supporting the achievement of the final investment decisions at large gas upstream projects (for example in Mozambique, Nigeria, Indonesia). We plan to accelerate the growth of our LNG portfolio and we expect to reach 14 million tons of contracted volumes of LNG by 2022, of which 70% deriving from our equity production;
(iii) leveraging integration with our downstream and upstream operations to extract better margins from the oil trading activity;
(iv) managing the commodity risk in the power business by means of risk management activities intended to reduce the market risk;
(v) increasing the profitability of the gas&power retail business, by enhancing the value of the existing customer base against the backdrop of escalating competitive pressures. This will be achieved by growing our customer base, by expanding the offer of new products and services other than the commodity and by continuing innovation in marketing processes including the deployment of digitalization in the acquisition of new customers, a reduction in the cost to serve and effective management of working capital.

Based on the above outlined trends and industrial actions, management expects that we will retain profitable, cash-positive operations in the Company's gas marketing business over the plan period. Our profitability outlook factors in the expected outcome of ongoing and planned renegotiations of the Company long-term supply contracts which the Company is seeking to finalize during the plan period, as well as other circumstances subject to risks and uncertainties described in Item 3.

Refining & Marketing

The outlook of the European refining sector is challenging due to structural headwinds in the industry pressured by overcapacity, high global stockpiles of gasoline, the impact of energy efficiency on fuel consumptions and rising competition from cheaper products streams from the Middle East and other areas, where large expansion projects in new refineries or in the upgrading of existing plants are anticipated. Furthermore, fuel demand in Europe is projected to stagnate due to an ongoing economic slowdown. Management expects refining margins to hover around the 4-5 $ per barrel range in the next four years and beyond. Further appreciation in the dollar vs. the euro exchange rate could negatively affect this target.

Against this backdrop, the Company priority is to retain profitable and cash-positive operations even in a depressed downstream oil environment. Our priority is to reduce the breakeven margin of Eni refineries, targeting 3 $ per barrel with the full operability of our refining system, particularly with the restart of the EST high-conversion unit at the Sannazzaro refinery and the recovery of the Bayernoil plant. Other measures include optimization of plant setup also in view of minimizing the yield of fuels with high sulfur content considering the enactment of new international rules on the sulfur content of bunkering, and a shift in the supply mix towards a higher quota of heavy crudes which normally trade at a discount over the Brent light crude benchmark. We expect higher contribution from our green refining complexes due to the planned start-up of the Gela revamped refinery and the ramp up of green volumes at the Venice refinery. Finally, we plan to pursue efficiency gains in logistics, to achieve energy savings and to improve plant reliability with the support of the deployment of a digital shift in our operations. We expect the profitability of our refining business will be boosted significantly once we close the acquisition of a 20% interest in the refining complex of Ruwais in UAE. The transaction is expected to close by end of 2019. Our refining capacity will increase by approximately 35% by adding an efficient, large-scale asset with high conversion, ample geographic reach and close to sources of raw materials. We expect this asset to remain profitable even in a depressed trading environment. We expect to implement a capex plan designed to upgrade this refinery and to enhance its profitability, resulting in a reduction of our average breakeven refining margin in the medium term down to 2.7 $/BBL and longer term to 1.5 $/BBL.

In Marketing activities, where we expect competitive pressure to continue due to muted demand trends, we are planning to improve results of operations mainly by focusing on innovation of products and services anticipating customer needs, strengthening our line of premium products, as well as efficiency in the marketing and distribution activities. Further value will be extracted by the development of our initiatives in the segment of sustainable mobility and new fuels (for example the recharging for electric vehicles, hydrogen and compressed natural gas) and selling non-fuel products and services.

Chemical

The outlook in the chemical business is challenging due to an ongoing economic slowdown in Europe, in China and in other emerging economies and rising competitive pressures from cheaper products stream in the main commoditized segments, like polyethylene, from producers in Middle East and in the US which can leverage on larger plant scale and lower feedstock costs (as in the case of ethane-feed crackers). In addition, our petrochemical commodities are exposed to the volatility of the crude oil-based feedstock costs. Over the last few years, we have restructured our business by reducing capacity, divesting or exiting unprofitable lines, plant optimization and other efficiency measures as well as a shift in our product portfolio towards specialties, green chemicals and products with high technology content, which are less exposed to the scenario volatility. Looking forward we believe that further steps are needed to preserve profitable and cash-positive operations. The industrial plan identified the following lines of action intended to improve resiliency to the market volatility: (i) strengthening the productive footprint by means of improved plant integration and reliability as well as by rightsizing our captive ethylene capacity vs internal needs for the production of polyethylene; (ii) improving feedstock flexibility by switching to ethane in feeding our crackers; (iii) upgrading the product mix by developing differentiated products, leveraging on new applications through internal R&D; (iv) developing the international presence of our chemical business leveraging on proprietary technologies targeting markets with growth opportunities and access to competitive feedstock and outlets; and (v) developing our portfolio of green products.

Capital expenditure plans

Over the next four years, the Company plans to invest €33 billion in the business, representing a modest increase from the previous plan. Approximately 77% of planned capital expenditures is expected to support continued organic growth in oil&gas production and exploration for the search of new reserves. Projects to support the Company long-term decarbonization targets and the development of the circular economy and renewables are expected to be assigned 9% of the Group overall budget for capital expenditures. The remaining part will fund selective growth opportunities in the R&M and Chemical segment. The above mentioned amount does not include the planned expenditures to acquire certain equity investments, particularly the acquisition of a 20% interest in the Ruwais refining complex in UAE with an expected expenditure of approximately €3 billion, which completion is forecast to occur by end of 2019. Eni's capital expenditure program is reflective of uncertainties about future trends in the oil markets and in the global macroeconomic environment. We intend to retain strict financial discipline going forward by focusing the more profitable projects in portfolio and phased approach to our larger projects to reduce our financial exposure.

We expect expenditure on development of oil&gas reserves over the next four years will be some €23 billion, of which approximately 65% directed to new field start-ups and ramp-ups, while the remaining 35% to production optimization and field re-vitalization. Project start-ups and plateau enhancement at existing fields will be geographically diversified and executed mainly in Egypt, with the full field development of the Zohr gas project, ramp up at the Norous complex and new start-ups, Nigeria, Italy, Mozambique to progress the large Coral and Mamba gas offshore fields, Libya, UAE, Iraq, Angola and Congo. Egypt will attract approximately 12% of the Group capital expenditure over the plan period.

Exploration capital expenditures will amount to €2 billion. Our projects will comprise near-field activities designed to recover additional reserves in areas close to existing production facilities and with fast time-to-market, as well as new initiatives targeting conventional prospects with high working interest in order to support Eni's dual exploration model in case of material discoveries. Finally, we forecast selective initiatives in high-risk, high-reward plays.

We are planning to invest approximately €4.3 billion in R&M and Chemical, which will be directed to selected initiatives of plant upgrading and development and initiatives intended to improve plant reliability and HSE standards.

Finally, we will invest approximately €3 billion in projects intended to reduce GHG emissions including projects designated to cut volumes of flared gas, to grow the green business and to develop the circular economy. Approximately 50% of those expenditures will be directed to build new power generation capacity from renewable sources (mainly photovoltaic cells and to a lesser extent wind power) at our industrial hubs in Italy, or as part of an integrated design with selected E&P initiatives outside Italy, targeting an installed production capacity of 1.6 gigawatt at the end of the plan period.

Management expects to pursue strict capital discipline when assessing individual capital projects. Management is assuming a long-term oil price of 70 $/BBL for the Brent benchmark, which is adjusted to take account of expected inflation rates from 2023 onwards. The internal rate of return of each project is compared to the relevant hurdle rate, differentiated by business segment and country of operation. These hurdle rates are calculated taking into account: (i) the weighted average cost of capital ("WACC") to the Group. In 2019, management assessed that the cost of capital to the Group increased marginally from 2017 to 7.3%, driven by higher yields on risk-free assets which are benchmarked to Italia ten-year sovereign bonds. A country risk premium is added to the Group WACC, which factors in the perceived level of risk associated with each of our countries of operations in terms of current trends and conditions in the macroeconomic, business, regulatory and socio-political framework, as well as the consensus outlook, and a premium for the business risk in determining the hurdle rates, which are utilized by management in its final investment decisions.

Liquidity and leverage

Considering uncertain future trends in the oil markets and in the global economy and price volatility, management's priorities remain to maximize cash generation from operating activities and to preserve a solid balance sheet. We believe the initiatives implemented by management during the downturn intended to increase efficiency in operations, to reduce the time-to-market of reserves, to select capital expenditures and to restructure the mid and downstream businesses together with the monetization of part of our recent exploration discoveries have improved the Company's fundamentals and strengthened its capital structure. We believe that in 2018 we have made further progress in enhancing the competitive position of the Company and its resiliency to the market volatility through a number of strategic deals aimed at rebalancing the asset portfolio along the hydrocarbons value chain and at increasing the geographic reach of our operations. Those deals included the acquisition of certain exploration and development E&P properties in the Middle East and the ongoing acquisition of a 20% interest in the Ruwais refining complex in Abu Dhabi. In future years, we will develop those acquisitions to extract the projected returns, while at the same time we expect to continue pursuing financial discipline and sustainable growth to drive profitable production increases, reserve replacement and margin expansion at our mid and downstream businesses.

Going forward, we plan to increase the Group's cash generation leveraging on the expected production growth and an improved sales volumes mix with the addition of more valuable barrels, as well as margin expansion in the mid-downstream businesses driven by synergies from integration, the repositioning of the refining activity and a growing customer base in the gas retail operations. These initiatives planned in the next four years are designed to reach a low price of the Brent crude oil at which the Company will be able to fund through cash flow from operations both the planned organic capital expenditures and the dividend.

Specifically, based on these actions and on the planned underlying growth in cash generation, we expect net cash provided by operating activities to fund the planned organic capital expenditure of $8 billion per year and the full dividend at around 50 $/BBL for the Brent crude, at the end of the plan period.

During the downturn, in spite of the sharp contraction in the operating cash flow due to lower oil prices, the Company has managed to hold its key ratio of net borrowings to equity – leverage – below a preset ceiling through a combination of cost cuts, asset disposals, capital expenditure curtailments and working capital optimization. At the end of 2018, our leverage stood at 0.16, down from 0.23 at the end of 2017 due to a stronger cash flow from operations driven by a combination of a better scenario and improved underlying performance. The Company intends to retain a strong control on the evolution of leverage going forward.

Our cash flows from operating activities are exposed to the volatility of the oil price environment. Currently, based on our portfolio of oil&gas properties, we estimate that, holding all other factors constant, our cash flow from operations vary by approximately €0.19 billion for each dollar change in Brent prices on a yearly basis compared to our price forecast of 62 $/BBL for 2019. We note that the Brent price in the period January 1 to March 31, 2019 was approximately 63 $/BBL on average (it was 67 $/BBL on average in the period January 1 to March 31, 2018). We retain some levels of financial flexibility that we may use in case oil prices should take another leg down in the cycle in the remainder of the year or in subsequent years. Particularly, approximately 50% of the planned investment for the years 2021 – 2022 has been allocated to projects yet to be sanctioned. In addition, we retain cash reserves and committed and uncommitted borrowing facilities.

For planning purposes, management assumed a EUR/USD exchange rate in the range of 1.15 – 1.21 U.S. dollars per euro in the 2019-2022 period. Given the sensitivity of Eni's results of operations to movements in the euro versus the U.S. dollar exchange rate, trends in the currency market represent a factor of risk and uncertainty. We note that in the period January 1 to March 31, 2019 the EUR/USD exchange rate was approximately 1.135 and weakened year-on-year (it was 1 EUR=1.23 USD in the first quarter of 2018). This trend will positively affect the reported amounts of operating profit and operating cash flow in our Exploration & Production segment. See "Item 3 – Risk factors".

IFRS 16 "Leases" will be applied by Eni with effect from January 1, 2019. Under the new standard, all lease contracts are recognized in the financial statements by way-of-right-of-use assets (ROU) and corresponding lease liabilities. Eni will apply the modified retrospective transition approach without restating comparative information.

The accounting of the new standard is summarized as follows:

- for each lease contract the Company will recognize an asset representing the right of use and the corresponding lease liability classified as part of finance liabilities. The Company expects to adopt the legal approach for Exploration & Production unincorporated joint operations where Eni is the operator. Under this approach, if, based on the contractual provisions and any other relevant facts and circumstances, Eni has primary responsibility for fulfilling the obligations associated with any lease contract, Eni recognise in the balance sheet: (i) the entire lease liability and (ii) the entire right-of-use asset, unless there is a sublease with the joint operators;

- in the profit and loss account: the Company will recognize the depreciation of the ROU and interest expense accrued on lease liabilities which are expected to offset the lowered operating expenses as result of lease fees being no longer recognized;

- in the cash flow statement: (a) the cash flow from operating activities is due to improve because reimbursement of the principal of each lease fee is no longer recognized among operating cash outflows; (b) net cash used in investing activities is due to improve because reimbursement of the principal of certain lease fees which are incurred in relation to the hire of equipment used in connection with a capital project is no longer recognized among cash outflows of investing activities; and (c) net cash used in financing activities will recognize cash payments in connection with reimbursement of the principal portion of each lease fee. However, no impact is expected on net cash for the period.

In summary we expect that in 2019 our statement of financial position will show a meaningful step up in finance liabilities in the range of €6 billion and a corresponding increase in the Group ratio of net borrowings to total equity – leverage, in the range of ten percentage points.

Further information about the first adoption of accounting standard IFRS 16 Leases is provided in the notes to the consolidated financial statements.

Remuneration policy

Management is committed to a progressive remuneration policy in line with our plans of underlying earnings and cash flow growth and considering the scenario evolution. Dividend growth will be driven by the results that ultimately will be achieved in implementing our strategy and by our ability to achieve the targeted Brent prices at which the Company's net cash provided from operating activities are able to fund planned capital expenditures and dividend payments. Considering the Company's outlook of improving results and business performance and the progress achieved so far in delivering on our financial and industrial targets, management is forecasting to increase the dividend expected for fiscal year 2019 to 0.86 €/share compared to 0.83 €/share for fiscal year 2018, up by 3.6%. Furthermore, the Company is contemplating resuming the share repurchase program as a flexible tool to return shareholders the cash in excess of that committed to achieve the targeted range of leverage. The time horizon of our share repurchase program is four years. In 2019, we expect to spend €400 million on share repurchases. In the next three years, provided that the Group leverage is steadily below 20% (before IFRS 16 impacts), management expects to spend €400 million per year in case the price of the Brent is comprised in the 60-65-dollar range, or €800 million in case of Brent prices above that range.

In future years, management expects to continue paying interim dividends for each fiscal year, with the balance for the full-year dividend paid in the following year.

The expectations described above are subject to risks, uncertainties and assumptions associated with the oil&gas industry, and economic, monetary and political developments in Italy and globally that are difficult to predict. There are a number of factors that could cause actual results and developments to differ materially, including, but not limited to, political instability in Libya and other countries, crude oil and natural gas prices; demand for oil&gas in Italy and other markets; developments in electricity generation; price fluctuations; drilling and production results; refining margins and marketing margins; currency exchange rates; general economic conditions; political and economic policies and climates in countries and regions where Eni operates; regulatory developments; the risk of doing business in developing countries; governmental approvals; global political events and actions, including war, terrorism and sanctions; project delays; material differences from reserves estimates; inability to find and develop reserves; technological development; technical difficulties; market competition; the actions of field partners, including the inability of joint venture partners to fund their share of operating or developments activities; industrial actions by workers; environmental risks, including adverse weather and natural disasters; and other changes to business conditions. Please refer to "Item 3 – Risk factors".

Off-balance sheet arrangements

Eni has entered into certain off-balance sheet arrangements, including guarantees, commitments and risks, as described in "Item 18 – Note 27 – Guarantees, commitments and risks – of the Notes on Consolidated Financial Statements". Eni's principal contractual obligations, including commitments under take-or-pay or ship-or-pay contracts in the gas business, are described under "Contractual obligations" below. See the Glossary for a definition of take-or-pay or ship-or-pay clauses.

Off-balance sheet arrangements comprise those arrangements that may potentially impact Eni's liquidity, capital resources and results of operations, even though such arrangements are not recorded as liabilities under generally accepted accounting principles. Although off-balance sheet arrangements serve a variety of Eni's business purposes, Eni is not dependent on these arrangements to maintain its liquidity and capital resources; nor is management aware of any circumstances that are reasonably likely to cause the off-balance sheet arrangements to have a material adverse effect on the Company's financial condition, results of operations, liquidity or capital resources.

Eni has provided various forms of guarantees on behalf of unconsolidated subsidiaries and affiliated companies, mainly relating to guarantees for loans, lines of credit and performance under contracts. In addition, Eni has provided guarantees on the behalf of consolidated companies, primarily relating to performance under contracts. These arrangements are described in "Item 18 – Note 27 – Guarantees, commitments and risks – of the Notes on Consolidated Financial Statements".

Contractual obligations

The amounts in the table refer to expected payments, undiscounted, by period under existing contractual obligations commitments.

	Total	2019	2020	2021	2022	2023	2024 and thereafter
Total debt	**27,157**	**6,928**	**2,971**	**1,542**	**1,274**	**2,714**	**11,728**
Long-term finance debt	23,490	3,301	2,958	1,541	1,253	2,714	11,723
Short-term finance debt	2,182	2,182					
Fair value of derivative instruments	1,485	1,445	13	1	21		5
Interest on finance debt	**3,963**	**655**	**545**	**436**	**330**	**320**	**1,677**
Guarantees to banks	**668**	**668**					
Non-cancelable operating lease obligations(1)	**3,953**	**776**	**601**	**481**	**303**	**268**	**1,524**
Decommissioning liabilities(2)	**13,814**	**335**	**294**	**407**	**260**	**124**	**12,394**
Environmental liabilities	**2,596**	**349**	**321**	**254**	**239**	**188**	**1,245**
Purchase obligations(3)	**131,824**	**14,674**	**11,258**	**10,649**	**9,683**	**9,546**	**76,014**
Natural gas to be purchased in connection with take-or-pay contracts(4)	125,872	11,886	10,470	9,995	9,276	9,210	75,035
Natural gas to be transported in connection with ship-or-pay contracts(4)	3,851	1,164	558	482	382	324	941
Other purchase obligations	2,101	1,624	230	172	25	12	38
Other obligations(5)	**116**	**8**	**1**	**1**	**1**	**1**	**104**
of which:							
– *Memorandum of intent relating to Val d'Agri*	*116*	*8*	*1*	*1*	*1*	*1*	*104*
TOTAL	**184,091**	**24,393**	**15,991**	**13,770**	**12,090**	**13,161**	**104,686**

(1) There are no significant restrictions provided by these operating leases which limit the ability of the Company to pay dividend, use assets or to take on new borrowings.

(2) Represents the estimated future costs for the decommissioning of oil and natural gas production facilities at the end of the producing lives of fields, well-plugging, abandonment and site restoration.

(3) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms.

(4) Such arrangements include non-cancelable, long-term contractual obligations to secure access to supply and transport of natural gas, which include take-or-pay or ship-or-pay clauses whereby the Company obligations consist of offtaking minimum quantities of product or service or paying the corresponding cash amount that entitles the Company to off-take the product in future years. Future obligations in connection with these contracts were calculated by applying the forecasted prices of energy or services included in the four-year business plan approved by the Company's Board of Directors and on the basis of the long-term market scenarios used by Eni for planning purposes to minimum take and minimum ship quantities. See "Item 4 – Gas & Power – Natural Gas Purchases" and "Item 3 – Risk Factors – Risks in the G&P business.

(5) In addition to these amounts, Eni has certain obligations that are not contractually fixed as to timing and amount, including contributions to defined benefit pension plans (See Note 21 to the Consolidated Financial Statements).

The amount of contractual commitments as of December 31, 2018 increased by approximately €25 billion from the amount stated at year-end 2017 mainly due to the forecast of higher gas prices compared with management's previous planning assumptions, which are utilized to valorize the gas volumes that the Company is committed to purchase under its current take-or-pay contracts.

The table below summarizes Eni's capital expenditures commitments for property, plant and equipment as of December 31, 2018. Capital expenditures are considered to be committed when the project has received the appropriate level of internal management approval. Such costs are included in the amounts shown below.

	Total	2019	2020	2021	2022	2023 and subsequent years
			(€ million)			
Committed projects	20,406	6,492	4,917	3,458	1,910	3,629

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace as to be unable to meet short-term finance requirements and to settle obligations.

Such a situation would negatively impact Group results as it would result in the Company incurring higher borrowing expenses to meet its obligations or under the worst of conditions the inability of the Company to continue as a going concern. At present, the Group believes it has access to sufficient funding and has also both committed and uncommitted borrowing facilities to meet currently foreseeable borrowing requirements. The Group has also established a cash reserve, which consists of cash on hand and very liquid financial assets (short-term deposits and held-for-trading securities). This cash reserve according to management plans can alternatively be used to absorb temporary swings in cash flows from operations, to provide financial flexibility to pursue the Group development programs or to fund the Group contractual obligations with respect to the repayment of financing debt at maturity over a 24-month horizon. For a description of how the Company manages the liquidity risk see "Item 18 – Note 27 of the Notes on Consolidated Financial Statements".

Working capital

Management believes that, taking into account unutilized credit facilities, the Company's liquidity reserves, our credit rating and access to capital markets, Eni has sufficient working capital for its foreseeable requirements.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay amount due. For a description of how the Company manages the credit risk see "Item 18 – Note 27 of the Notes on Consolidated Financial Statements".

For information about credit losses in 2018 and the allowance for doubtful accounts see "Item 18 – Note 7 of the Notes on Consolidated Financial Statements".

Market risk

In the normal course of its operations, Eni is exposed to market risks deriving from fluctuations in commodity prices and changes in the euro versus other currencies exchange rates, particularly the U.S. dollar, and in interest rates. For a description of how the Company manages the Market risk see "Item 18 – Note 27 of the Notes on Consolidated Financial Statements".

Research and development

For a description of Eni's research and development operations in 2018, see "Item 4 – Research and development".

Item 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

Directors and Senior Management

The following table lists the Company's Board of Directors as at December 31, 2018:

Name	Position	Year elected or appointed	Age
Emma Marcegaglia	Chairman	2014	53
Claudio Descalzi	CEO	2014	63
Andrea Gemma	Director	2014	45
Pietro A. Guindani	Director	2014	60
Karina A. Litvack	Director	2014	56
Alessandro Lorenzi	Director	2011	70
Diva Moriani	Director	2014	50
Fabrizio Pagani	Director	2014	51
Domenico Livio Trombone	Director	2017	58

In accordance with Article 17.1 of Eni's By-laws, the Board of Directors is made up of 3 to 9 members.

The current Board of Directors was elected by the ordinary Shareholders' Meeting held on April 13, 2017 which also established the number of Directors at nine for a term of three financial years. The Board's term will therefore expire with the Shareholders' Meeting called to approve the financial statements for the year ending December 31, 2019.

The Board of Directors is appointed by means of a slate voting system: slates may be presented by the shareholders representing at least 0.5% of share capital. According to the Eni By-laws, three out of nine Directors are appointed from among the candidates of the non-controlling shareholders.

Emma Marcegaglia, Claudio Descalzi, Andrea Gemma, Diva Moriani, Fabrizio Pagani and Domenico Livio Trombone were the candidates of the Ministry of the Economy and Finance. Pietro A. Guindani, Karina Litvack and Alessandro Lorenzi were the candidates of institutional investors (non-controlling shareholders). The Shareholders' Meeting appointed Emma Marcegaglia as the Chairman of the Board of Directors and, on April 13, 2017, the Board appointed Claudio Descalzi as the Chief Executive Officer of the Company.

Three Directors out of nine, including the Chairman, were drawn from the less represented gender, reaching the ratio of one-third of the Directors as provided by the law.

The following provides details on the personal and professional profiles of the Directors.

Emma Marcegaglia was born in Mantua in 1965 and has been Chairman of Eni since May 2014. She has been Chairman of the Fondazione Eni Enrico Mattei since November 2014. She is also Chairman and CEO of Marcegaglia Holding SpA and Deputy Chairman and CEO of the subsidiary companies operating in the processing of steel. She is also Chairman and CEO of Marcegaglia Investments Srl, the holding company of the diversified activities of the group. She is President of the Luiss Guido Carli University and a member of the Board of Directors of Bracco SpA and Gabetti Property Solutions SpA. From 1994 to 1996 she was National Deputy President of Young Entrepreneurs of Confindustria, from 1997 to 2000 she was President of the European Confederation of the Young Entrepreneurs (YES), from 1996 to 2000 President of Young Italian Entrepreneurs of Confindustria and from 2000 to 2002 she was Vice President of Confindustria for Europe. From May 2004 to May 2008 she was Confindustria Vice President for infrastructures, energy, transport and environment and Italian Representative of the top High Level Group for energy, competitiveness and environment set up by the European Commission. From May 2008 to May 2012 she was President of Confindustria. From July 2013 to July 2018 she was President of Businesseurope. She was a member of the Management Board of Banco Popolare and Director of Finecobank SpA and Italcementi SpA. She also held the position of Chairman of the Aretè Onlus Foundation. She graduated in Business Administration at the Bocconi University in Milan and attended a Master in Business Administration at New York University.

Claudio Descalzi was born in Milan and has been Eni's CEO since May 2014. He is a member of the General Board and of the Advisory Board of Confindustria and Director of Fondazione Teatro alla Scala. He is a member of the National Petroleum Council. He joined Eni in 1981 as Oil & Gas field petroleum engineer and then became project manager for the development of North Sea, Libya, Nigeria and Congo. In 1990 he was appointed Head of Reservoir and operating activities for Italy. In 1994, he was appointed Managing Director of Eni's subsidiary in Congo and in 1998 he became Vice President & Managing Director of Naoc, a subsidiary of Eni in Nigeria. From 2000 to 2001 he held the position of Executive Vice President for Africa, Middle East and China. From 2002 to 2005 he was Executive Vice President for Italy, Africa, Middle East, covering also the role of member of the board of several Eni subsidiaries in the area. In 2005, he was appointed Deputy Chief Operating Officer of the Exploration & Production Division in Eni. From 2006 to 2014 he was President of Assomineraria and from 2008 to 2014 he was Chief Operating Officer in the Exploration & Production Division of Eni. From 2010 to 2014 he held the position of Chairman of Eni UK. In 2012, Claudio Descalzi was the first European in the field of Oil&Gas to receive the prestigious "Charles F. Rand Memorial Gold Medal 2012" award from the Society of Petroleum Engineers and the American Institute of Mining Engineers. He is a Visiting Fellow at The University of Oxford. In December 2015 he was made a member of the "Global Board of Advisors of the Council on Foreign Relations". In December 2016 he was awarded an Honorary Degree in Environmental and Territorial Engineering by the Faculty of Engineering of the University of Rome, Tor Vergata. In July 2018 he has joined the mothers2mothers UK Board of Trustees. He graduated in physics in 1979 from the University of Milan.

Andrea Gemma was born in Rome in 1973 and has been Director of Eni since May 2014. He is Professor of Private Law at The Third University of Rome and was visiting professor at European Universities and at Villanova University. He is member of the Strategic Board of the American University of Rome. He is Appeal Court Lawyer. He is President of Board of Statutory Auditors of PS Reti SpA and Sirti SpA. He is also Official Receiver of Valtur SpA, Liquidator of Novit Assicurazioni SpA and Sequoia Partecipazioni SpA.

Pietro A. Guindani was born in Milan in 1958 and has been Director of Eni since May 2014. Since July 2008 he has been Chairman of the Board of Directors of Vodafone Italia SpA, where between 1995-2008 he was Chief Financial Officer and subsequently Chief Executive Officer. He previously held positions in the Finance Departments of Montedison and Olivetti and started his career in Citibank after graduating in Business at the Università Luigi Bocconi in Milan. He is currently also a Board member of the Italian Institute of Technology and Cefriel-Polytechnic of Milan. He is Board Member of Confindustria and Member of the Executive Board of Confindustria Digitale; he is President of Asstel-Assotelecomunicazioni and Vice President responsible for Universities, Innovation and Human Capital of Assolombarda. He was also Director of Société Française du Radiotéléphone – SFR S.A. (2008-2011), Pirelli & C. SpA (2011-2014), Carraro SpA (2009-2012), Sorin SpA (2009-2012), Finecobank SpA (2014-2017) and Salini-Impregilo SpA (2012-2018).

Karina A. Litvack was born in Montreal in 1962 and has been a Director in Eni since May 2014. She is currently a member of the Global Advisory Council in Cornerstone Capital Inc., a member of the Advisory Board in Bridges Ventures LLC, a member of Business for Social Responsibility and of Yachad, a member of the Advisory Council for Transparency International UK and a member of the Senior Advisory Panel of Critical Resource. From 1986 to 1988 she was a member of the Corporate Finance team of PaineWebber Incorporated. From 1991 to 1993 she was a Project Manager of the New York City Economic Development Corporation. In 1998 she joined F&C Asset Management plc where she held the position of Analyst Ethical Research, Director Ethical Research and Director Head of Governance and Sustainable Investments (2001-2012). She was also a member of the Board of the Extractive Industries Transparency Initiative (2003-2009) and of the Primary Markets Group of the London Stock Exchange Primary Markets Group (2006-2012). From January 2010 to November 2017 she was member of the CEO Sustainability Advisory Panel in SAP AG. She graduated in Political Economy at the University of Toronto and in Finance and International Business from Columbia University Graduate School of Business.

Alessandro Lorenzi was born in Turin in 1948 and has been Director of Eni since May 2011. He is Director of Ersel SIM SpA and of Mutti SpA. He began his career at SAIAG SpA in the Administration and Control area. In 1975 he joined Fiat Iveco SpA where he held a series of positions: Controller of Fiat V.I. SpA, Head of Administration, Finance and Control, Head of Personnel of Orlandi SpA in Modena (1977-1980) and Project Manager (1981-1982). In 1983 he joined GFT Group where he was Head of Administration, Finance and Control of Cidat SpA, a GFT SpA subsidiary (1983-1984), Central Controller of GFT Group (1984-1988), Head of Finance and Control of GFT Group (1989-1994) and Managing Director of GFT SpA, with ordinary and extraordinary powers over all operating activities (1994-1995). In 1995 he was appointed Chief Executive Officer of SCI SpA, where he oversaw the restructuring process. In 1998 he was appointed Operating Officer and was subsequently Director of Ersel SIM SpA until June 2000. In 2000 he became Executive Officer of Planning and Control at the Ferrero Group and General Manager of Soremartec, the technical research and marketing company of the Ferrero Group. In May 2003 he was appointed CFO of Coin Group and in 2006 he became Chief Corporate Officer at Lavazza SpA, becoming Board member from 2008 to June 2011. From July 2011 to September 2017 he was Chairman of Società Metropolitana Acque Torino SpA.

Diva Moriani was born in Arezzo in 1968 and has been a Director in Eni since May 2014. She is currently Executive Vice Chairman of Intek Group SpA, Vice Chairman of KME AG, a German holding company of KME Group, Director of KME Srl, Member of the Supervisory Board of KME Germany GmbH and Director of Assicurazioni Generali SpA, Moncler SpA, Dynamo Academy, Dynamo Foundation and Associazione Dynamo. From 2007 to 2012 she was CEO of I2 Capital Partners, a private equity fund sponsored by Intek Group SpA, with an investment strategy focused on "Special Situations" and from 2014 to 2017 CEO of KME AG. She graduated in Economics at the University of Florence.

Fabrizio Pagani was born in Pisa in 1967 and has been a Director in Eni since May 2014. He is Global Head of Economics and Capital Market Strategy of Muzinich & Co. and Board member of Save SpA, Banca Finint SpA, Engineering SpA, Eurosky Holdings Ltd and Eurosky Srl. From 2014 to 2018 he has been Head of the Office of the Minister of Economy and Finance. He was Deputy Director of the International Training Programme for Conflict Management at the High School S. Anna in Pisa from 1995 to 1998, Professor of International Law in the Faculty of Political Science at the University of Pisa from 1993 to 2001, Deputy Chief of the Legislative Office at the Department of European Affairs from 1998 to 1999 and Counsellor for International Affairs in the Ministry of Industry and Foreign Trade from 1999 to 2001. He was Senior Advisor at the OECD from 2002 to 2006, Head of the Office of the State Undersecretary, within the Prime Minister Office from 2006 to 2008, board member of SACE SpA from 2007 to 2008, Political Counsellor of the OECD General Secretary from 2009 to 2011, Director of the G8/G20 Office at the OECD from 2011 to 2013 and Senior Economic Counsellor to the Prime Minister and G20 Sherpa from 2013 to 2014. He was a NATO Fellow and was a visiting scholar at Columbia University, New York. He graduated in International Studies at the Scuola Superiore Sant'Anna, Pisa, and has a Master degree from the European University Institute, Florence.

Domenico Livio Trombone was born in Potenza in 1960 and has been Director of Eni since April 2017. He is a certified chartered accountant and a certified public auditor. He is partner of Studio Trombone Dottori Commercialisti e Associati. He is currently Chairman of the Board of Directors of Consorzio Cooperative Costruzioni-CCC, of Focus Investments SpA and of Società Gestione Crediti Delta SpA. He is, among the others, Director of Aeroporto Guglielmo Marconi di Bologna SpA and of International World Group Srl. Furthermore, he is Chief Executive Officer of Atrikè SpA and Sole Director of FINCCC SpA and of Focus Investment International Srl. He is also Chairman of the Board of Statutory Auditors of Coop Alleanza 3.0 Sc, Unipol Banca SpA, Cooperativa Immobiliare Modenese Soc. Coop., H2I SpA and of Tenute del Cerro SpA. He is standing Statutory Auditor, among the others, of: Arca Assicurazioni SpA, Arca Vita SpA, CCFS Soc. Coop, Cooperare SpA, Il Ponte SpA, PLT Energia SpA, Unipol Finance SpA, Unipol Investment SpA, UnipolPart I SpA and Unisalute SpA. He is Liquidator in Italcarni Sc and in Open.Co S.c. He is technical consultant in legal proceedings, coadjutor in bankruptcy proceedings, liquidator, trustee in bankruptcy and judicial commissioner. Over the years he held positions in banks, in asset management and insurance companies. More in detail, he was standing Statutory Auditor in Carimonte Holding SpA, Unicredit Servizi Informativi SpA, Immobiliare Nettuno Srl and Gespro SpA. From April 2006 to March 2007 he was Director of Aurora Assicurazioni SpA. From October 2007 until the merger of the Company in FonSai SpA, he was Chairman of the Board of Statutory Auditors in Unipol Assicurazioni SpA. Until December 2008 he was Director in Banca Popolare del Materano SpA and BNT Consulting SpA. From April 2010 to October 2011 he was Chairman of the Board of Directors in BAC Fiduciaria SpA. From April 2009 to December 2011 he was Chairman of the Board of Statutory Auditors in Arca Impresa Gestioni SGR SpA. From April 2007 until April 2012 he was Chairman of the Board of Statutory Auditors in Cassa di Risparmio di Cento SpA. From April 2010 to May 2016 he was Chief Executive Officer of Carimonte Holding SpA, becoming Chairman until 26 July 2018. From December 2011 to December 2012 he was independent Director in Serenissima SGR SpA. From

December 2011 to April 2016 he was Director and Vice Chairman in Gradiente SGR SpA. From April 2007 to April 2016 he was Standing Statutory Auditor of Unipol Gruppo Finanziario SpA. He graduated in Economics from the University of Modena.

Senior Management

The table below sets forth the composition of Eni's Senior Management as of the date of the filing. It includes the CEO, as General Manager of Eni SpA, as well as the Chief Officers and the Executives who report directly to the CEO and to the Board, and on its behalf, to the Chairman.

Name	Management position	Year first appointed to current position	Total number of years of service at Eni	Age
Claudio Descalzi	CEO and General Manager of Eni	2014	37	63
Luca Bertelli	Chief Exploration Officer	2014	34	60
Alessandro Puliti	Chief Development, Operations & Technology Officer	2018	28	55
Claudio Granata	Chief Services and Stakeholder Relations Officer	2014	35	58
Massimo Mantovani	Chief Gas & LNG Marketing and Power Officer	2016	25	55
Massimo Mondazzi	Chief Financial Officer	2014	26	55
Luigino Lusuriello	Chief Digital Officer	2018	30	57
Giuseppe Ricci	Chief Refining & Marketing Officer	2016	33	60
Antonio Vella	Chief Upstream Officer	2014	35	61
Marco Bollini[1]	Legal Affairs Senior Executive Vice President	2016	21	52
Marco Petracchini	Internal Audit Senior Executive Vice President	2011	19	54
Roberto Ulissi	Corporate Affairs and Governance Senior Executive Vice President and Board Secretary and Corporate Governance Counsel	2006	12	56
Marco Bardazzi	External Communication Executive Vice President	2015	3	51
Luca Cosentino	Energy Solutions Executive Vice President	2015	15	57
Lapo Pistelli	International Affairs Executive Vice President	2017	3	54
Luca Franceschini	Integrated Compliance Executive Vice President	2016	27	52
Jadran Trevisan	Integrated Risk Management Executive Vice President	2016	18	57

The Chief Exploration Officer, the Chief Development, Operations & Technology Officer, the Chief Upstream Officer, the Chief Gas & LNG Marketing and Power Officer, the Chief Refining & Marketing Officer, the Chief Financial Officer, the Chief Services & Stakeholder Relations Officer, Chief Digital Officer, the Senior Executive Vice President Legal Affairs, the Senior Executive Vice President Internal Audit, the Senior Executive Vice President Corporate Affairs and Governance, as well as the Executive Vice President Energy Solutions, the Executive Vice President External Communication, the Executive Vice President International Affairs, the Executive Vice President Integrated Compliance, the Executive Vice President Integrated Risk Management, are members of the Management Committee[2], which provides advice and support to the Chief Executive Officer. Other managers may be invited to attend meetings based on the agenda. The Chairman of the Board is invited to attend meetings. The duties of Committee Secretary are performed by the Senior Executive Vice President Corporate Affairs and Governance.

The Chief Financial Officer has been appointed as Officer in charge of preparing Company's financial reports pursuant to Italian law by the Board of Directors, acting upon a proposal of the CEO in agreement with the Chairman, following consultation with the Nomination Committee and with the approval of the Board of Statutory Auditors.

[1] On January 1, 2019 Marco Bollini was appointed Commercial Negotiations Senior Executive Vice President and Stefano Speroni was appointed Legal Affairs Senior Executive Vice President.

[2] The Commercial Negotiations Senior Executive Vice President is also member of the Management Committee since January 1, 2019. The Committee includes also the CEOs of certain Eni's subsidiaries.

The Senior Executive Vice President Internal Audit is appointed by the Board of Directors, acting upon a proposal of the Chairman in agreement with the Chief Executive Officer (in his capacity as Director in charge of the internal control and risk management system), following consultation with the Board of Statutory Auditors and the Nomination Committee and with the favorable opinion of the Control and Risk Committee.

The Board Secretary and Corporate Governance Counsel is appointed by the Board of Directors upon a proposal of the Chairman.

Other members of Eni's senior management are appointed by Eni's CEO and may be removed without cause.

Senior Managers

Luca Bertelli was born in Sesto Fiorentino on October 5, 1958. He graduated with honours in geology in 1983 from the University of Florence. In 1984 he joined Eni's geophysics division, working first as a researcher in the development of 3D seismic prospecting technology and subsequently as a manager of 3D seismic prospecting programmes, specialising in seismic-stratigraphy. In 1994 he was appointed manager of seismic-stratigraphy applications and in 1999 he increased the technical-managerial scope of his activities becoming manager of geological and geophysical services in Eni.

At the end of 2001, his career took a new international turn holding positions of increasing managerial complexity over a period of eight years, starting in Norway where he was Technical Director and Deputy Managing Director at Norsk Agip in Norway. In 2003 he was appointed Managing Director of Eni Indonesia and in 2006 he moved to Egypt as General Manager and Managing Director, a position he also held at Eni Angola in 2007. In 2009 he returned to Eni's headquarters as Senior Vice Chairman of Global Exploration. He was appointed Executive Vice President of Exploration and Unconventional at the beginning of 2010. Since July 1, 2014, he has been Eni's Chief Exploration Officer.

Alessandro Puliti was born in Florence on June 23, 1963. He joined Agip SpA's Reservoir Department in 1990 as a Reservoir Geologist and was involved in the study of reservoirs in Africa and Italy. His international professional career started in 1998, when he moved to Aberdeen to fill the position of Assistant Operated Asset Manager of Agip UK, where he gained operational experience in complex contexts. After returning to Italy in 2002, he was appointed Reservoir and Drilling and Completion Manager in the Val D'Agri project. In 2003 he was posted to Egypt as IEOC's Development and Operations Manager and subsequently covered increasingly more complex managerial roles, first as General Manager and Managing Director of Petrobel and later as General Manager of IEOC. In 2009 he moved back to Italy to take on the role of Regional Management Russia and North Europe Vice President. In 2010, he moved to Stavanger, where he held the dual role of Eni Norge's Managing Director and Regional Management Russia and North Europe Vice President. In 2012 he returned to the HQ Operations Department, first as Senior Vice President Petroleum Engineering, Production and Maintenance and then as Senior Vice President Drilling and Completion and Deputy Operations. In October 2015 he was appointed Reservoir & Development Projects Executive Vice President. He graduated with Honors in Geology from the University of Milan and earned the MEDEA Master in Energy and Environmental Management and Economics from "Scuola Mattei". He is the author of several papers on reservoirs and drilling presented at international conferences. He was appointed as Chief Development, Operations & Technology Officer on September 18, 2018.

Claudio Granata was born in Rome in 1960. Graduating with a degree in economics, he joined the Eni group in 1983. From 1983 to 1994 worked as a labour market and social welfare expert with ASAP (the trade union association for Eni Companies). From 1994 to 1999 he continued his experience with Eni Corporate as an expert in industrial relations. In 2000 he was made responsible for Staff and Organisation within Eni Servizi Amministrativi, a company that was set up to centralise Eni's administrative activities.

In 2001 he took over the management of Eni's territorial divisions, restructuring the management of staff by geographical area and in 2003 he took on the role of Business HR for Eni Corporate, ensuring support for departments in the management and development of Eni Corporate's managerial resources during a period of profound change (2002-2004), which was characterised by the mergers of Snam and AgipPetroli and the restructuring of staff organisation. In the same year he was also appointed head of Human Resources and Organisation of SOFID (Eni's financial services company).

In 2006 he was appointed Human Resources Director of the E&P Division, where he oversaw the planning, management, development and compensation processes for human resources and organization activities. He also collaborated with the top management in the reorganisation of macro processes for the division and promoted change management initiatives.

He became a board member of Eni International Resources Ltd in 2006 and was Chairman of the board of Eni International Resources Ltd from 2012 to 2013. From 2012 to March 2015 he was a board member of Eni UK ltd.

In 2013 he was appointed Executive Vice President Sustainable Development, Safety, Environment and Quality at E&P, responsible for overseeing safety, environment and quality processes to promote integration with operational processes and contribute to improvements in "time to market" and efficiency. From 2014 to May 2016, he was a member of the Board of Directors of the Eni Foundation. He has been Chairman of the board of Eni Corporate University since November 2014. He has been Chief Services & Stakeholder Relations Officer in Eni since 1 July 2014.

Massimo Mantovani was born in Milano in 1963. He graduated with a degree in law from the University of Milan and holds a Master's Degree from the University of London. He is the author of numerous publications. After qualifying to practice law in Italy and UK he worked for few years in private legal practice in Milan and London. In 1993 he joined Eni's Legal Department, specializing in international negotiations and contracts, specifically on international gas/LNG supplies and projects and joint ventures for the commercialization and transport of gas. In 2001 he was appointed legal Director of Eni's Gas & Power Division. His main task was participating to the management for Eni of the start-up phase of the liberalization of the gas market in Italy and the unbundling of the national and international network for the transport of gas. In October 2005 he was appointed Senior Executive Vice President of Legal Affairs in Eni SpA.

He has been Chief Legal and Regulatory Affairs in Eni from 2014 to 2016, the department managed all legal and energy regulatory issues of Eni and its non-listed subsidiaries. From October 17, 2016 to August 3, 2017 he has been Chief Midstream Gas & Power Officer.

From 2005 to 2016 he was member of Eni SpA. Watch Structure. He was a member of the Board of Directors in Snam Rete Gas SpA from 2005 to 2012 and of the Board of University of Bologna from 2011 to 2012.

He has been Chairman of Syndial SpA from 2016 to 2017. Since November 2016 Mr. Mantovani seats on behalf of Eni in the Governing Board and in the Executive Committee of Eurogas, the association representing the European gas sectors firms. He is Chairman of Anigas, the Italian association of Gas industry, from December 2017 and member of the Confindustria Energia presidential board.

Between 2011 and 2014 he has been a member of the anticorruption working group for the B20, coordinator for activities relating to the development of an international regulatory framework for the B20 held in Russia in 2013 and leading expert for the 2014 B20 in Australia.

He is Eni's Chief Gas & Lng Marketing and Power Officer since 4 August 2017.

He is Chairman of Eni Trading & Shipping SpA since November 2016 and from February 2018 he has also been appointed CEO of the company in charge of Gas, LNG and Power activities.

Massimo Mondazzi was born in Monza in 1963. He graduated in Economics and Business Administration from Bocconi University Milan in 1987. He joined Eni in 1992 after acquiring considerable professional experience in industrial companies and also as a management consultant. He worked in the Administration and Control area of the Exploration and Production Division until 2006, becoming Director. From 2006 to 2009 he was Director of Planning and Control for the Eni Group, before returning to E&P as Executive Vice President for the Central Asia, Far East and Pacific Region business areas. In this role he contributed to the consolidation of Eni's activities in the Exploration and Production division, to the launch of new development projects and to Eni's entry into new countries. On December 5, 2012 he was appointed Chief Financial Officer of Eni and Officer charged with preparing the company's financial reports pursuant to Article 154-bis of Legislative Decree No. 58/1998. He is Chairman of Agi SpA since 2013. From 2014 until September 2016, alongside his role as Eni's Chief Financial Officer, he was also responsible for Eni's Integrated Risk Management.

Luigino Lusuriello was born in Genoa on August 9, 1961. He joined Agip SpA's Engineering Department in 1988 as a designer engineer of onshore and offshore structures. In 1994 he was appointed Operating and Maintenance Technologies Manager at Crema District and then he grows in the Production Area up to the role of Production Manager of Ortona District. In 2001 he was appointed Ortona District

Manager and later Val d' Agri District Manager. From 2004 he began an international career path, initially as Technical Director in Congo, where, the year after, he was appointed Managing Director. In 2007 he took on the role of Managing Director in ENI UK. He returned to Italy in 2009 to take on the role of Vice President for Regional Management of Kazakhstan-Karachaganak activities. From 2011, following the entry of Eni in Iraq, he has been in charge for the development project as Senior Vice President of the Iraq Program. In 2013 he was appointed Executive Vice President Operations. He graduated with 110/110 in Mechanical Engineering from the University of Genoa and completed the course "The Oxford Advanced Management and Leadership Program" at the Said Business School, University of Oxford. He has been Chief Digital officer in Eni since September 18, 2018.

Giuseppe Ricci was born in Casale Monferrato in 1958. He joined Eni in 1985 initially working in the study and development of new refining processes at the Sannazzaro refinery, before becoming involved in the creation and consolidation of the joint venture with Kuwait Petroleum at the Milazzo refinery. In 2000 he returned to head office as where he was responsible for Refining Processes Development and oversaw the performance optimisation at the refining facilities of Agip Petroli. He left central technologies to take over, in 2004, as director of the Gela Refinery, a particularly challenging assignment both from a managerial perspective and in terms of the refining cycle and the complexity of the plant; in 2006 he was appointed managing director of the refinery. In June 2010 he was made Senior Vice President of the Industrial Sector for Refining & Marketing, with responsibility for the refineries, storage deposits, oil pipelines and plant and facilities in Italy, as well as the management of subsidiary and associated companies in Italy and abroad. As Industrial Director he also held a series of additional responsibilities, such as the chairmanship of Gela and Milazzo. In 2012 he took on the delicate role of Eni's Executive Vice President Health, Safety Environment and Quality with responsibility for providing the guidelines, coordination and control of safety, industrial health, product safety, the environment and quality. He has been President of Confindustria Energia since July 2017 and President of AIDIC (Italian Association Of Chemical Engineering) since 2018. He has a degree in chemical engineering. He was appointed as Chief Refining & Marketing Officer on September 12, 2016.

Antonio Vella. He was born in Tripoli (Libya) in 1957. He has been a board member of Eni Foundation since July 2014. He joined the Eni Group in 1983 beginning his career as an oil engineer at Agip in Libya, where he was involved in upstream onshore and offshore operations. From 1988 to 1991, he was project manager for Enichem's petrochemical plants and refineries in Italy. In 1991 he was appointed project manager for the development of Libyan oil fields and in 1993 he moved to Egypt, initially as Operations Manager and subsequently as General Manager and Managing Director of Petrobel, where he was responsible for all of Eni's upstream operations in Egypt. In 1999 he was appointed District General Manager of Nigerian Agip Oil Co (NAOC), and in 2000 became Vice Chairman and Managing Director of the Eni companies in Nigeria NAOC, NAE (Nigerian Agip Exploration) and AENR (Agip Energy). In 2002 he became regional Vice President for Australasia, Russia, Azerbaijan and in 2005 a member of the Board of Directors and Managing Director of Eni Algeria. From 2006 to 2009 he was regional Senior Vice President for North Africa and the Middle East (Algeria, Tunisia, Egypt, Libya, Mali, Morocco, Iran, Iraq, Saudi Arabia) for Eni's Exploration & Production Division and since 2009, Executive Vice President Operations of the Exploration & Production Division. In December 2012, he was appointed Executive Vice President for Central Asia, the Far East and the Pacific area. He graduated in engineering from Turin Polytechnic in 1982. Since July 1, 2014, he has been Chief Upstream Officer.

Marco Bollini was born in Milan in 1966. He graduated with a degree in law from the University of Milan and he is registered to practice law on the special list of the Ordine degli Avvocati (the Italian Bar Association) of Milan. After graduating, he worked as a lawyer for a few years in a law firm in Milan. He joined Eni in 1997 in the Legal Department of Agip SpA, mainly following international legal projects until 2001 when he took on the responsibility of International Legal Assistance of Exploration and Production Division. In 2005 he was appointed Legal Director of the Gas &Power Division, further diversifying his business knowledge. In 2007, he is back in the Exploration & Production Division as Legal Director. In 2008, following the centralization of the Eni's legal function into one Legal Department, he took on responsibility for the legal assistance to the company's activities outside Europe. In 2013 he was appointed Executive Vice President International Business Legal Area and, in 2015, he became Executive Vice

President International and Finance Legal Affairs of Eni, with a strong exposure to international matters, with a particular focus on the Upstream business and management of partnerships and M&A transactions. Since 2016, he has been a Board Member of Eni Foundation. He was appointed Senior Executive Vice President Legal Affairs on October 17, 2016[3].

Stefano Speroni was born in Milano in 1962. Stefano Speroni has accumulated vast experience in over 30 years of professional activity in the field of corporate affairs, mergers and acquisitions, private equity operations and capital markets. He has given professional support to Italian and International listed companies (in a wide range of sectors including aerospace and defence, oil & gas, telecommunications, transport and infrastructure) in strategic corporate affairs, in share trading, joint ventures and commercial agreements. From January 2016 to December 2018, he was a Managing Partner for Corporate M&A in Dentons' Italian practice. In 2012, he was one of the founders of the Grimaldi Legal Studio, after having previously been managing partner of Dewey Ballantine's Rome practice which involved managing its Italian activities for around 10 years. He was also a partner in Studio Gianni, Origoni, Grippo Capelli & Partners (2001 – 2003), in the Simmons and Simmons Italian practice (1991 – 2001), and manager of the European Corporate Department and member of the World-wide Remuneration Committee. He is a member of the scientific committee and contributor to SDA Bocconi's Private Equity Laboratory and was awarded "Best Lawyer of the Year" 2018 by the Best Lawyers international directory. He graduated in Law at Università degli Studi in Milan and is a registered member of the Italian Bar Association in Milan. Since January 1, 2019, he has been Legal Affairs Senior Executive Vice President.

Marco Petracchini was born in Rome in 1964. He graduated Cum Laude with a degree in economics from La Sapienza University in Rome in 1989. After graduation, he was hired by Esso Italiana where he held various positions in the IT, Finance and Auditing sectors. He joined Eni in 1999 in the Internal Audit Department, gradually taking on positions of increasing responsibilities: Head of Downstream Audit activities and Head of Support Process Audit activities (in particular IT and Fraud Audit). He is also a Member of the Watch Structure of Eni SpA and Secretary of the Control and Risk Committee of Eni SpA. He holds international qualifications as well, in detail: Certified Internal Auditor (CIA), Certified Fraud Examiner (CFE), Certified Risk Management Assurance (CRMA). He is currently a Board Member of AiiA (Italian Internal Auditors Association). He is Eni's Senior Executive Vice President Internal Audit.

Roberto Ulissi was born in Rome in 1962. He is a lawyer. After a number of years spent as a lawyer at the Bank of Italy, in 1998 he was appointed General Manager at the Ministry of the Economy and Finance head of the Banking and Financial System and Legal Affairs Department. He was a Board member of Telecom Italia (and Chairman of the Audit Committee), Ferrovie dello Stato, Alitalia, Fincantieri and a government representative on the Governing Council of the Bank of Italy. He is a board member and Vice Chairman of Banor SIM. He was also a member of numerous Italian and European committees representing the Ministry of the Economy including, at a national level, the Commission for the Reform of Corporate Law (Commission "Vietti") and, at EU level, the Financial Services Policy Group, the Banking Advisory Committee, the European Banking Committee, the European Securities Committee, and the Financial Services Committee. He was also special professor of banking law at the University of Cassino. He is Grande Ufficiale della Repubblica Italiana. Since 2006, he has been Senior Executive Vice President Corporate Affairs and Governance and a Board Member of Eni International BV. He is currently Board Secretary of Eni and, since 2014, Corporate Governance Counsel and Company Secretary. Since May 2018, he has been Coordinator of the Corporate Governance Forum of Company Secretaries.

Marco Bardazzi was born in Prato in 1967. He is a professional journalist working in the media world for 28 years before joining Eni in 2015. He has gained extensive experience on foreign policy and digital communications, particularly in Europe and America. Between 2009 and 2015 he was Managing Editor and Digital Editor at "La Stampa". He was a key member of the team that worked on the transformation of a traditional newspaper to an integrated digital news organization, creating an innovative "concentric circles" multiplatform newsroom. He was one of the co-founders of "Europa" a partnership between La Stampa, Le Monde, El País, The Guardian, Gazeta Wyborcza and Suddeutsche Zeitung. Before joining "La Stampa", he was U.S. correspondent for the Italian news agency ANSA between 2000 and 2009, covering every aspect of American life for the Italian media. Among other things, he covered the Bush-Gore electoral race for the White House in 2000, the first international Al Qaeda trial in Manhattan, the September 11 attack on America, the wars in Afghanistan, and Iraq and the 2004 and 2008 presidential campaigns. He has visited and reported on the Guantanamo detention camp at the U.S. Navy Guantanamo Bay base in Cuba. He won the Saint-Vincent Award for Journalism for a series of reports on the death

[3] He was appointed Senior Executive Vice President Commercial Negotiations on January 1, 2019.

penalty in the USA. He covered the 2008 financial crisis, and he reported extensively on the American digital, energy and automobile industries.

He holds an Associate of Arts degree in History from American Public University. His latest book is "L'Ultima Notizia" (with Massimo Gaggi, Rizzoli 2010), an essay on digital transformation in the media business. He is an external lecturer in the Masters in Journalism in ALMED-Università Cattolica del Sacro Cuore, Milan. He is a Visiting Fellow at the University of Oxford. In 2017 he was appointed as a Director of Agi SpA and Eni Gas e Luce. Since February 2015, he has been External Communication Executive Vice President.

Luca Cosentino was born in Venice on August 1, 1961. He graduated cum laude with a degree in geology in 1985 from the University of Padua and joined Eni in 1986. He spent the first years of his professional life in the Reservoir Department, within the reservoir modeling group. Between 1992 and 1996, he worked in different operational positions in Italy and abroad in the reservoir sector. From 1996 to 2003, he worked as Project Manager with IFP (Institut Français du Petrol, France), in Venezuela and in the Persian Gulf. In this period, he also taught at the IFP School and published several technical papers, including a book on Integrated Reservoir Studies. Upon his return to Eni in 2003, he was appointed Head of the Reservoir Department and, in 2004, Head of the Reservoir Modeling Department. From 2005 to 2010, he was in Libya, initially as Operation and Asset Manager with Eni North Africa and then as Member of the Management Committee in the operating company Eni Oil, later Mellitah Oil & Gas. From 2010 to 2013, he has been Managing Director of Eni Congo. In 2013, he was appointed Senior Vice President Non Operated Business Performance and Stranded Resources Valorization. Since November 1, 2015, he has been Executive Vice President Energy Solutions.

Lapo Pistelli was born in Florence in 1964. Having graduated with honors in 1988 in International Law at the Political Science faculty "Cesare Alfieri" at the University of Florence, he started working at a research center, while serving for two mandates in the local administration of Florence. He was member of the Italian Parliament from 1996 to 2015 (1996/2004 and 2008/2015), and also member of the European Parliament (2004/2008). As an Italian MP, he was member of the Committees on Constitutional Affairs, European Affairs and on International Affairs. As a MEP in Brussels, he worked at the Economic and Monetary Affairs and Foreign Affairs Committees. During this period, he has also been the President of the EU-South Africa Delegation and a member of the Italian Delegation to the OSCE, where he conducted several monitoring missions in transitional democracies.

He served as Deputy Minister of Foreign Affairs and International Cooperation of Italy from 2013 to 2015. He resigned from all his institutional and political roles in July 2015, when he entered Eni as Senior Vice President for Strategic Analysis for Business Development Support. He was appointed Executive Vice President in April 2017. He taught and lectured at the University of Florence, the Overseas Studies Program of Stanford University and many others international academic institutions. He regularly contributed to many European and American think tanks and research centers specialized in international relations. He is a member of the board of the European Council on Foreign Relations (ECFR), of the Istituto Affari Internazionali (IAI), of the editorial board of Oil and of the scientific committee of EastWest. As a journalist, he regularly publishes in various newspapers issues related to European and international affairs and on specialized magazines, such as Limes. He authored several publications: in his last book, Il nuovo sogno arabo – Dopo le rivoluzioni, Feltrinelli 2012, he analyses the origin and challenges of the 'Arab Spring' and its impact on the geo-political scenario in North Africa and the Middle East.

Luca Franceschini was born in Milan in 1966. He is a graduate in Law from the University of Milan and is registered to practice law on the special list of the Ordine degli Avvocati (the Italian Bar Association) in Rome. He first joined in Eni in 1991 in the legal department of Agip SpA, initially involved in disputes and providing legal assistance to the procurement area, before going on to delivering legal support for a range of national and international projects in the Exploration & Production sector. In 2000, in the context of the process for the liberalisation of the natural gas sector, he was involved in the spin-off of the gas storage business and the creation and launch of Sogit SpA, for which he became head of Legal and Corporate Affairs. He made his return to Eni SpA in 2005 as head of Italian Legal Assistance in the Gas & Power division. Following the concentration of all legal functions in Eni's central Legal Department, he was engaged in providing legal support in the regulatory and antirust areas, gradually extending his responsibilities and becoming, in 2009, head of Legal Assistance for the business and Antitrust issues in Italy, as well as council for legal assistance for the activities of the Refining & Marketing sector. He was also a member of the boards of directors of both Italgas and Stogit. In 2015 he was appointed as Eni's Executive Vice President for Legal and Regulatory Compliance. He was appointed as Executive Vice President of Integrated Compliance on September 12, 2016.

Jadran Trevisan was Born in Milan in 1961. He has a degree in philosophy and a Master's in business administration from SOGEA, the management school of Confindustria Liguria. After a short period at Gabetti, in 1991 he joined the Fininvest Group, where he was involved in financial communications and was part of the project for the listing of Mediaset for which, in 1995, he became the Investor Relations Manager. In 2000 he joined Eni as head of Investor Relations, where, in addition to participating in a number of significant extraordinary operations (the listing of Snam Rete Gas, the de-listing of Italgas), he oversaw relations with institutional investors. In 2006 he was appointed head of Business Strategy at Eni's E&P division, where he was involved in the acquisition of significant assets and companies operating in the upstream sector. In 2008 he was appointed CFO of the recently acquired subsidiary Distrigas, where, for the following three years, he was engaged in consolidating and aligning the company's business and financial processes with those of Eni and rationalising the company structure. In 2011 he was part of the project for the creation of Eni Trading & Shipping SpA, becoming its Senior Vice President for Operations & Control. From the end of 2012 until July 2015 he was Senior Vice President Credit and in August 2015 he was appointed Senior Vice President for Integrated Risk Management. Since September 12, 2016 he reports directly to the Chief Executive Officer in his role as Executive Vice President Integrated Risk Management.

Compensation

The information concerning compensation is provided in the remuneration report prepared in accordance to Italian listing standards, which is incorporated herein by reference.

See the Exhibit 15. a (i).

As of December 31, 2018, the total amount accrued to the reserve for employee termination indemnities with respect to Chief Executive Officer and General Manager, Chief Executive Officers and other Managers with strategic responsibilities (with reference to the employed ones who, during the course of the 2018 period, filled said roles, even if only for a fraction of the year), was €1,612 thousand.

Name		(€ thousand)
Descalzi Claudio	Chief Executive Officer	366
Senior managers[(a)]		1,246
		1,612

(a) No. 20 managers.

Board practices

Corporate Governance

The Corporate Governance structure of Eni follows the Italian traditional management and control model, whereby corporate management is the responsibility of the Board of Directors, which is the core of the organizational system, while supervisory functions are allocated to the Board of Statutory Auditors. The Company's accounts are independently audited by an accredited Audit Firm appointed by the Shareholders' Meeting. Eni complies with the Corporate Governance Code for listed companies (on the Italian Stock Exchange) approved by Italian Corporate Governance Committee (hereinafter "Corporate Governance Code" or "Code"), lastly amended on July 2018.

The names of Eni's Directors, their positions, the year in which each of them was initially appointed as a Director and their ages are reported in the related table above.

Board of Directors' duties and responsibilities

The Board of Directors has the fullest powers for the ordinary and extraordinary management of the Company in relation to its purpose. In a resolution dated April 13, 2017, the Board, while exclusively reserving to itself the most important strategic, operational and organizational powers, in addition to those that cannot be delegated by law, appointed Claudio Descalzi as CEO and General Manager, entrusting him with the fullest powers for the ordinary and extraordinary management of the Company, with the exception of those powers that cannot be delegated under current law and those retained by the Board.

In the same resolution, the Board of Directors resolved to confirm to the Chairman a major role in internal controls and not operational functions. In particular, with reference to Internal Audit, the Board of Directors resolved that, in accordance with the Corporate Governance Code, the Head of the Internal Audit Department reports to the Board, and on its behalf, to the Chairman, without prejudice to its functional reporting to the Control and Risk Committee and the Chief Executive Officer, as the director in charge of the internal control and risk management system. The Chairman is also involved in the appointment of the primary Eni officers in charge of internal controls and risk management, as well as in approving internal rules governing the Internal Audit process. In addition, the Chairman carries out her statutory functions as legal representative, managing institutional relationships in Italy, together with the Chief Executive Officer.

Finally, the Board of Directors entrusted the Board Secretary with the role of Corporate Governance Counsel, who reports hierarchically and functionally to the Board and, on its behalf, to the Chairman. He lends assistance and independent legal advice to the Board and the Directors and periodically presents to the Board of Directors a report on the functioning of Eni's Corporate Governance system.

On April 13, 2017, the Board reserved to itself the strategic, operational and organizational powers briefly described below:

- defines the system and rules of Corporate Governance for the Company and the Group;
- establishes the Board's internal committees, appoints their members and chairmen, determines their duties and compensation, and approves their procedural rules and annual budgets;
- expresses the general criteria for determining the maximum number of offices that a Director may hold in other companies;
- delegates and revokes the powers of the CEO and the Chairman, establishing the limits and procedures for exercising those powers and determining the compensation associated with these duties;
- establishes the basic structure of the organizational, administrative and accounting arrangements of the Company (including the internal control and risk management system), of its strategically important subsidiaries and of the Group as a whole. It evaluates the adequacy of these arrangements;
- establishes the guidelines for the internal control and risk management system, so that the main risks facing the Company and its subsidiaries are correctly identified and adequately measured, managed and monitored, determining the degree of compatibility of such risks with the management of the Company in a manner consistent with its stated strategic objectives. It sets the financial risk limits of the Company. It also examines the main business risks, which are identified taking into account the characteristics of the activities carried out by the Company and its subsidiaries and which are reported by the Chief Executive Officer at least quarterly. Moreover, it evaluates, every six months, the adequacy of the internal control and risk management system with respect to the characteristics of the Company and its risk profile, as well as the system's effectiveness;
- approves at least annually the Audit Plan drawn up by the Senior Executive Vice President of the Internal Audit Department. It also evaluates the findings contained in the recommendation letter, if any, of the Audit Firm and in its statement on the key issues that arose during the statutory audit;
- defines the strategic guidelines and objectives of the Company and the Group, including sustainability policies. It examines and approves the budgets and strategic, industrial and financial plans of the Group, periodically monitoring their implementation, as well as agreements of a strategic nature for the Company. It examines and approves the plan for the Company's non-profit activities and approves operations not included in the plan whose cost exceeds €500,000;
- examines and approves the annual financial report (which includes Eni's draft Financial Statements and the Consolidated Financial Statements) and the semi-annual and quarterly financial reports required by applicable law. It reviews and approves the Sustainability Reporting when it is not already contained in the financial report;
- receives reports from Directors with delegated powers at Board meetings, or on at least a bi-monthly basis, on the actions taken in exercising their delegated powers;
- receives a report from the Board's internal committees on at least a semi-annual basis;
- assesses general developments in the operations of the Company and of the Group, paying particular attention to conflicts of interest and comparing the results with budget forecasts;

- evaluates and approves transactions of the Company and its subsidiaries with related parties provided for in the procedure approved by the Board[4], as well as transactions in which the CEO has an interest;
- evaluates and approves any transaction executed by the Company and its subsidiaries that has a significant strategic, economic, financial or asset impact on the Company;
- appoints and removes the Chief Operating Officers, the Officer in charge of preparing financial reports, the Senior Executive Vice President of the Internal Audit Department and the Eni Watch Structure. It ensures the designation of a manager responsible for shareholder relations;
- examines and approves the Remuneration Report and, in particular, the Remuneration Policy for Directors and Managers with strategic responsibilities to be presented to the Shareholders' Meeting. It also defines the criteria for remunerating the senior executives of the Company and of the Group and takes steps to implement compensation plans based on shares or other financial instruments approved by the Shareholders' Meeting;
- resolves on the exercise of voting rights and on the appointment of members of corporate bodies of the strategically important subsidiaries;
- formulates the proposals to present to the Shareholders' Meeting; and
- examines and resolves on other issues that Directors with delegated powers believe should be presented to the Board due to their particular importance or sensitivity.

In accordance with Article 23.2 of the By-laws, the Board also resolves on mergers and proportional spin-offs of companies in which Eni's shareholding is at least 90%; the establishment and closing of branches; and the amendment of the By-laws to comply with the provisions of law.

In accordance with the By-laws, the Chairman and the Chief Executive Officer retain representative powers for the Company.

Directors' independence

On the basis of statements made by the Directors and other information available to the Company, during its meeting of April 13, 2017 and, after an investigation by the Nomination Committee, lastly at its meeting of February 14, 2019, the Board of Directors determined that Chairman Marcegaglia and Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Trombone satisfy the independence requirements established by law, as referenced in Eni's By-laws. Furthermore, Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Trombone have been deemed independent by the Board pursuant to the criteria and parameters recommended by the Corporate Governance Code. Chairman Marcegaglia, in compliance with the Corporate Governance Code, could not be deemed independent as she is a significant representative of the Company.[5]

At the last assessment, the Board of Directors also evaluated that the commercial relationships between Eni and Vodafone Italy, a company of which Director Guindani is a significant representative, and between Eni and companies of the KME Group, companies subject to significant influence, also indirectly, by Director Moriani, are not significant for the purpose of assessing the independence of these Directors, having regard to the nature and the amounts of these relationships. The relationships were evaluated on the basis of statements made by the Directors and other information available to the Company, and taking into account that – due to the nature of the companies mentioned above – transactions between these companies and Eni were subject to related parties' transactions regulation and reported to the Company's body.

The Board of Statutory Auditors always verified the proper application of criteria and procedures adopted by the Board of Directors in assessing the independence of its members.

The independence criteria may not be equivalent to the independence criteria set forth in the NYSE listing standards applicable to a U.S. domestic company.

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[4] The Board of Directors, on November 18, 2010, approved the Management System Guideline (MSG) "Transactions involving interests of Directors and Statutory Auditors and transactions with related parties", which has been applied since January 1, 2011, to ensure transparency and substantial and procedural fairness of transactions with related parties. The Board modified this MSG on January 19, 2012 and, lastly, on April 4, 2017.

[5] Although the Chairman of the Board of Directors is a non-executive Director, the Code treats her as a significant representative of the Company (Application Criterion 3.C.2 of the Corporate Governance Code).

Board Committees

The Board of Directors has established four internal Committees to provide it with recommendations and advice: (a) the Control and Risk Committee; (b) the Remuneration Committee; (c) the Nomination Committee; and (d) the Sustainability and Scenarios Committee. Committees under letters (a), (b) and (c) are recommended by the Corporate Governance Code. The composition, duties and operational procedures of these committees are governed by their own rules, which are approved by the Board, in compliance with the criteria outlined in the Corporate Governance Code.

The Committees recommended by the Corporate Governance Code are composed of no fewer than three members and, in any case, less than a majority of members of the Board. The composition is described in the following sections pertaining each Committee.

All Board Committees report to the Board of Directors, at least once every six months, on activities carried out. In addition, the Chairmen of the Committees report to the Board at each meeting of the Board on the key issues examined by the Committees in their previous meetings.

In the exercise of their functions, the Committees have the right to access any information and Company functions necessary to perform their duties. They are also provided with adequate financial resources, in accordance with the terms established by the Board of Directors, and can avail themselves of external advisers.

The Chairman of the Board of Statutory Auditors or a Statutory Auditor designated by him, participates in Control and Risk Committee and Remuneration Committee meetings and may participate in other Committees' meetings. Furthermore, Committees may invite other persons to attend the meetings in relation to individual items on the agenda.

The CEO and the Chairman may attend the meetings of the Nomination Committee and of the Sustainability and Scenarios Committee. Furthermore, they may attend Control and Risk Committee meetings, unless matters relating to them are discussed. Finally, they may attend Remuneration Committee meetings upon the invitation of its Chairman, except when the meetings are examining proposals regarding their remuneration[6].

The Board Secretary and Corporate Governance Counsel coordinates the secretaries of the Board Committees, receiving at this end information on the calendar of the meetings and the items in the Committees' agendas, the notices of the meetings, as well as their signed minutes.

Minutes of all Committee meetings are usually drafted by their respective secretaries. The current members of the Control and Risk Committee, Remuneration Committee, Nomination Committee and Sustainability and Scenarios Committee were appointed by the Board of Directors on April 13, 2017.

Remuneration Committee

Members: Andrea Gemma (Chairman), Pietro A. Guindani, Alessandro Lorenzi, Diva Moriani.

The Remuneration Committee is made up of non-executive, independent Directors. All the members possess adequate professional requirements and expertise for carrying out the duties assigned to the Committee. The Committee's rules require that at least one of its members possess adequate knowledge and experience of financial matters or remuneration policies, as assessed by the Board at the time of his or her appointment.

Established by the Board of Directors for the first time in 1996, in accordance with the By-laws, the Committee provides recommendations and advice to the Board of Directors. More specifically, the Committee:

6 Rules of the Remuneration Committee establish that "no Director and, in particular, no Director with delegated powers may take part in meetings of the Committee during which Board proposals regarding his remuneration are being discussed, unless are deemed proposals on all the members of the Committees established within the Board of Directors."

a) submits the Remuneration Report and in particular the Remuneration Policy for Directors and Managers with strategic responsibilities to the Board of Directors for approval, prior to its presentation at the Shareholders' Meeting called to approve the year's financial statements, in accordance with the time limits set by applicable law;
b) periodically evaluates the adequacy, overall consistency and effective implementation of the Policy, formulating proposals, as appropriate, for approval by the Board of Directors;
c) presents proposals for the remuneration of the Chairman and the Chief Executive Officer, including the various components of compensation and non monetary benefits;
d) presents proposals for the remuneration of Board Committee members;
e) having examined the Chief Executive Officer's indication, proposes general criteria for the compensation of Managers with strategic responsibilities, the annual and Long-Term incentive plans, including equity-based ones, sets performance objectives and assesses performance against them, in connection with the determination of the variable portion of the remuneration for Directors with delegated powers and with the implementation of the approved incentive plans;
f) monitors execution of decisions taken by the Board;
g) reports at the first available meeting of the Board of Directors through the Committee Chairman on the most significant issues addressed by the Committee during the meetings. It also reports to the Board on its activities at least every six months and no later than the time limit for the approval of the Annual Report and the Interim Report at 30 June, at the Board meeting designated by the Chairman of the Board of Directors.

Furthermore, in exercising its functions, the Committee may issue opinions as required by Company procedures in relation to operations with related parties, in accordance with specified procedures.

The Committee performs its duties pursuant to an annual plan. In carrying out its duties, the Committee may access the information and Company functions necessary to perform its duties and can avail itself of external advisors who are not in positions that might compromise their independence of judgement, within the terms and budget limits established by the Board of Directors.

The Committee reports on the procedures it adopts in performing its functions to the Shareholders' Meeting called to approve the financial statements through its Chairman or another Committee member designated by the Chairman, in accordance with the recommendations in the Corporate Governance Code and with the goal of establishing and appropriate channel for dialogue with shareholders and investors.

During 2018, the Remuneration Committee met eight times, with an average attendance of 100% of its members and an average duration of 2 hours and 30 minutes. At least one member of the Board of Statutory Auditors participated in each meeting, whit constant participation of the Chairman of the Board of Statutory Auditors.

Earlier in the year, the Committee focused its activities in particular on the following topics:

i. periodic evaluation of Remuneration Policy implemented in 2017 in order to prepare the proposed policy guidelines for 2018, providing for keeping the structure and criteria of remuneration of the Directors and Executives with strategic responsibilities defined in 2017 for the entire term, as regards in particular the simplified variable incentive system, as discussed in greater detail in the 2017 Remuneration Report;
ii. verification of the Company's 2017 results for the purpose of implementing the Short- and Long-Term variable incentive plans, using a predetermined gap analysis method approved by the Committee in order to neutralize the positive or negative impact of exogenous factors and enable the objective assessment of the performance achieved;
iii. definition of 2018 performance targets relevant to the variable incentive plans;
iv. finalizing the proposal for the implementation of the annual variable incentive system for the Chief Executive Officer and General Manager;
v. review of the 2018 Eni Remuneration Report;
vi. review of the outcome of the engagement activities held with leading institutional investors and proxy advisors in view of the general meeting, in order to maximize shareholder consensus on the 2018 Remuneration Policy; the Chairman of the Committee also took part in the aforementioned meetings, bearing witness to the importance given by the Committee to dialogue with shareholders;

vii. risk assessment and scenario analysis, and related voting projections arrived at with the assistance of primary international consulting firm;
viii. examination of the voting recommendations issued by the main proxy advisors and, following the findings, start of a further intense engagement activity with a large number of investors, to with dispatch of a letter explaining the reasons and the rationale for the choices made.

As regards further relevant activities carried out, the Committee:
i. examined the 2018 Shareholders' Meeting vote results, with regard to the Eni Remuneration Report, compared to the results of the main Italian and European listed companies and of the Peer Group;
ii. finalized the proposal (2018 grant) for the implementation of the 2017 – 2019 Long-Term Share Incentive Plan for the Chief Executive Officer and General Manager and for key management personnel;
iii. reviewed the general criteria for defining the 2019 engagement plan, through the performance of preliminary analysis and segmentation activities of institutional investors at the 2018 Shareholders' Meeting;
iv. carried out a periodic monitoring of developments in the legislative and regulatory environment and in market standards for the representation of information on remuneration issues, with a specific focus, for 2019, on contents of the EU Directive 828/2017 ("SHRD II Directive");
v. started the review of 2019 Remuneration Report Policy Guidelines, with the support of the competent Company functions.

The composition and appointment, as well as the duties and operational procedures, of the Committee are governed by the Rules approved by the Board of Directors, available to the public on the Company's website (https://www.eni.com/docs/en_IT/enicom/company/governance/rules-of-the-remuneration-committee.pdf).

Control and Risk Committee

Members: Alessandro Lorenzi (Chairman), Andrea Gemma, Karina Litvack and Diva Moriani.

The Control and Risk Committee is entrusted with supporting, on the basis of an appropriate control process, the Board of Directors in evaluating and making decisions concerning the internal control and risk management system and in approving the periodical financial reports. It is entirely made up of non-executive and independent Directors[7] who possess the necessary expertise consistent with the duties they are required to perform[8].

In particular, at their appointment, the Directors Lorenzi, Litvack and Moriani were identified by the Board as members with "adequate experience in the area of accounting and finance or risk management", as recommended by the Corporate Governance Code.

The Committee advises the Board of Directors and specifically issues its prior opinion: a) and drafts recommendations concerning the guidelines for the internal control and risk management system so that the main risks faced by the Company and its subsidiaries can be correctly identified and appropriately measured, managed and monitored and also supports the Board in determining the degree of compatibility of such risks with the management of the Company in a manner consistent with its stated strategic objectives; b) on the assessment, performed by the Board of Directors, on the main company risks, identified taking into account the characteristics of the activities carried out by the company or its subsidiaries; c) on the evaluation, performed at least every six months, of the adequacy of the internal control and risk management system, taking account of the characteristics of the Company and its risk profile, as well as its effectiveness. To this end, at least once every six months it reports to the Board of Directors, on the occasion of the approval of the annual and semi-annual financial reports, on its activities and on the adequacy of the internal control and risk management system at the meeting of the Board of

[7] In accordance with the rules of the Control and Risk Committee, the Committee is made up of three to four non-executive Directors, all of whom are independent. Alternatively, the Committee may be made up of non-executive Directors, a majority of whom shall be independent. In the latter case, the Chairman of the Committee shall be chosen from among the independent Directors. In any case, the number of members shall be fewer than the number representing a majority on the Board.
[8] The Governance system put in place by Eni establishes that at least two members of the Committee– and not just one as recommend by the Corporate Governance Code for listed companies – must possess adequate experience in financial and accounting matters or in risk management, as assessed by the Board of Directors at the time of their appointment.

Directors indicated by the Chairman of the Board of Directors; d) on the approval, at least once a year, of the Audit Plan prepared by the Senior Executive Vice President of the Internal Audit Department; e) on the description, in the annual Corporate Governance Report, of the main features of the internal control and risk management system, and how the different subjects involved therein are coordinated, providing its evaluation of the overall adequacy of the system itself; and f) on the evaluation of the findings reported by the Audit Firm in any recommendations letter it may issue and in the latter's report on the main issues arising during the audit.

The Committee furthermore: a) issues opinions to the Board of Directors on specific aspects concerning the identification of the main risks faced by the Company; b) examines and issues an opinion on the adoption and amendment of the rules on the transparency and the substantive and procedural fairness of transactions with related parties and those in which a Director or Statutory Auditor holds a personal interest or an interest on behalf of a third party, while performing additional duties assigned it by the Board of Directors, including examining and issuing an evaluation on specific types of transactions, except for those relating to compensation; and c) gives an opinion on the fundamental guidelines of the Regulatory System, the regulatory instruments to be approved by the Board of Directors, their amendment or update and, upon request by the CEO, on specific aspects in relation to the instruments implementing the fundamental guidelines.

In addition, the Committee, in assisting the Board of Directors: a) evaluates, together with the Officer in charge of preparing financial reports and after having consulted the Audit Firm and the Board of Statutory Auditors, the proper application of accounting standards and their consistency in preparing the Consolidated Financial Statements, prior to their approval by the Board of Directors; b) examines and evaluates Reports prepared by the CFO/Officer in charge of preparing financial reports through which it shall give its opinion to the Board of Directors on the appropriateness of the powers and resources assigned to the Officer himself and on the proper application of accounting and administrative procedures, enabling the Board to exercise its legally mandated supervision tasks; c) at the request of the Board, it supports, with adequate preliminary activities, the Board of Directors' assessments and resolutions on the management of risks arising from detrimental facts of which the Board may have become aware and d) monitors the independence, adequacy, efficiency and effectiveness of the Internal Audit Department and oversees its activities with respect to the duties of the Board of Directors in this area, and on its behalf, of the Chairman, ensuring that they are performed with the necessary independence and required level of objectivity, competence and professional diligence, in accordance with the Code of Ethics of Eni SpA and international standards.

A favorable opinion of the Committee is required for the approval to the Board on proposals by the Chairman in agreement with the CEO concerning the appointment, the removal and, consistent with the Company's policies, the structure of the fixed and variable compensation of the Senior Executive Vice President of the Internal Audit Department, as well as on the adequacy of the resources provided to the latter to perform his duties.

The Committee also: a) evaluates, on the occasion of his appointment, whether the Senior Executive Vice President of the Internal Audit Department meets the integrity, professionalism, competence and experience requirements and, on an annual basis, assesses their fulfilment; b) examines the results of the audit activities performed by the Internal Audit Department; c) examines the periodic reports prepared by the Senior Executive Vice President of the Internal Audit Department as to whether it contains adequate information on the activities carried out, on the manner in which risk management is conducted and on compliance with risk containment plans, as well as assesses the appropriateness of the internal control and risk management system. It also examines the reports prepared promptly by the Senior Executive Vice President of the Internal Audit Department on events of particular importance; and d) examines the information received from the Senior Executive Vice President of the Internal Audit Department and promptly reports its assessment to the Board of Directors in the case of: (i) significant deficiencies in the system for preventing irregularities and fraudulent acts, and irregularities or fraudulent acts committed by management personnel or by employees that perform important roles in the design or operation of the internal control and risk management system; and (ii) circumstances that may affect the maintenance of the independence of the Internal Audit Department and of auditing activities.

The Committee may also ask the Internal Audit Department to perform audits on specific operational areas, providing simultaneous notice to the Chairman of the Board of Statutory Auditors. The Committee also examines and assesses: a) communications and information received from the Board of Statutory

Auditors and its members regarding the internal control and risk management system, including those concerning the findings of enquiries conducted by the Internal Audit Department in connection with reports received (whistleblowing), including anonymous reports; b) half yearly reports issued by Eni's Watch Structure, including in its capacity as Guarantor of the Code of Ethics, as well as the timely updates provided by the Structure, after the updates have been given to the Chairman of the Board and to the CEO, about any particular material or significant situation detected in the performance of its duty; c) information on the internal control and risk management system, including that provided in the course of periodic meetings with the competent Company structures; and d) enquiries and reviews concerning the internal control and risk management system carried out by third parties.

Furthermore, the Committee oversees the activities of the Legal Affairs Department in case of judicial inquiries and proceedings, carried out in Italy and/or abroad, in relation to the CEO and/or the Chairman of the Company and/or a member of the Board of Directors and/or an Executive reporting directly to the CEO, even if no longer in office, for crimes against the Public Administration and/or corporate crimes and/or environmental crimes, related to their mandate and their scope of responsibility.

The composition and appointment, as well as duties and operational procedures of the Committee, are governed by rules approved by the Board of Directors lastly on May 9, 2017 available to the public at the Company's website.

Nomination Committee

Members: Diva Moriani (Chairman), Andrea Gemma, Fabrizio Pagani and Domenico Livio Trombone.

The Nomination Committee is made up of non-executive Directors, a majority of whom are independent.

The Committee provides recommendations and advice to the Board of Directors. More specifically, the Committee:

a) assists the Board of Directors in formulating any criteria for the appointment of those persons indicated in letter b) below, and of the members of the other boards and bodies of Eni's subsidiaries and associated companies;
b) provides evaluations to the Board of Directors on the appointment of executives and members of the boards and bodies of the Company and of its subsidiaries, proposed by the Chief Executive Officer and/or the Chairman of the Board of Directors, whose appointment falls under the Board's responsibility and oversees the associated succession plans. Where possible and appropriate, and with due regard to the shareholding structure, the Committee proposes the CEO succession plan to the Board of Directors;
c) acting upon a proposal of the Chief Executive Officer, examines and evaluates criteria governing the succession planning for the Company's managers with strategic responsibilities;
d) proposes candidates to serve as Directors to the Board of Directors in the event one or more positions need to be filled during the course of the financial year (Article 2386, first paragraph, of the Italian Civil Code), ensuring compliance with the requirements regarding the minimum number of independent Directors and the percentage reserved for the less represented gender;
e) proposes to the Board of Directors candidates for the position of Director to be submitted to the Shareholders' Meeting of the Company, taking account of any recommendations received from shareholders, in the event it is not possible to draw the required number of Directors from the slates presented by shareholders;
f) oversees the annual self-assessment program on the performance of the Board of Directors and its Committees, in compliance with the Corporate Governance Code, and deals with the preliminary activity for appointing an external consultant for such self-assessment. On the basis of the results of the self-assessment, the Committee provides its opinions to the Board of Directors regarding the size and composition of the Board or its Committees, as well as, the skills and managerial and professional qualifications it feels should be represented within the same Board and Committees so that the Board itself can give its opinion to the shareholders prior to the appointment of the new Board;

g) proposes to the Board of Directors the slate of candidates for the position of Director to be submitted to the Shareholders' Meeting if the Board decides to opt for the process envisaged in Article 17.3, first period, of the By-laws;
h) in compliance with the Corporate Governance Code, proposes to the Board of Directors guidelines regarding the maximum number of positions of Director or Statutory Auditor that a Company Director may hold and performs the preliminary activity for the associated periodic checks and evaluations for submission to the Board;
i) periodically verifies that the Directors satisfy the independence and integrity requirements, and ascertains the absence of circumstances that would render them incompatible or ineligible;
j) provides its opinion to the Board of Directors on any activities carried out by the Directors in competition with the Company;
k) through the Chairman of the Committee, informs the Board of Directors on the main issues examined by the Committee thereof during the first available meeting of the Board; furthermore, the Committee reports to the Board of Directors, at least once every six months and no later than the deadline for the approval of the annual and semi-annual financial report, on the activity carried out as well as on the adequacy of the appointment system, at the Board meeting indicated by the Chairman of the Board of Directors.

The preliminary examination of corporate affairs or governance issues is carried out jointly with the Senior Executive Vice President Corporate Affairs and Governance who, in this case, participates in the Committee meetings.

The composition, appointment, duties and operational procedures of the Nomination Committee are governed by rules approved by the Board of Directors lastly on May 9, 2017, available to the public at the Company's website.

Sustainability and Scenarios Committee

Members: Pietro A. Guindani (Chairman), Karina Litvack, Fabrizio Pagani and Domenico Trombone.

The Sustainability and Scenarios Committee is made up of non-executive Directors, a majority of whom are independent.

The Sustainability and Scenarios Committee provides recommendations and advice to the Board of Directors on scenarios and sustainability, i.e. the processes, projects and activities aimed at ensuring the Company's commitment to sustainable development along the value chain, particularly with regard to: health, well-being and safety of people and communities; respect and the protection of rights, particularly of the human rights; local development; access to energy, energy sustainability and climate change; environment and efficient use of resources; integrity and transparency; and innovation.

Board of Statutory Auditors

The current Board of Statutory Auditors was appointed by the Ordinary Shareholders' Meeting of April 13, 2017 for a term of three financial years. The Board's term will therefore expire with the Shareholders' Meeting called to approve the Financial Statements for the year ending December 31, 2019.

Name	Position	Year first appointed to Board of Statutory Auditors
Rosalba Casiraghi	Chairman	2017
Enrico Maria Bignami	Auditor	2017
Paola Camagni	Auditor	2014
Andrea Parolini	Auditor	2017
Marco Seracini	Auditor	2014
Stefania Bettoni	Alternate	2014
Claudia Mezzabotta	Alternate	2017

Paola Camagni, Andrea Parolini, Marco Seracini and Stefania Bettoni (Alternate) were candidates listed in the slate presented by the Ministry of the Economy and Finance; Rosalba Casiraghi (Chairman), Enrico Maria Bignami and Claudia Mezzabotta (Alternate) were candidates listed in the slate presented by non-controlling shareholders.

The Auditors are appointed by means of a slate voting system: the lists are presented by shareholders representing at least 0.5% of the share capital. Two standing Statutory Auditors and one Alternate Auditor are selected from among the candidates of the non-controlling shareholders. The Chairman of the Board of Statutory Auditors is appointed by the Shareholders' Meeting from among the Auditors chosen by the non-controlling shareholders.

In accordance with the provisions designed to ensure gender balance, two Statutory Auditor were drawn from the less represented gender.

The Auditors must satisfy the independence, professional and integrity requirements established by Italian regulations. Article 28 of the By-laws specifies that the professionalism requirements may be fulfilled by having at least three years' experience in: (i) professional or teaching activities pertaining to commercial law, business economics and corporate finance, or (ii) experience in executive positions in the fields of engineering and geology. U.S. Regulations for Audit Committees require that at least one member of the Board of Statutory Auditors be a financial expert and have adequate knowledge of the functions of the Audit Committee and experience in the analysis and application of generally accepted accounting standards, the preparation and auditing of Financial Statements and internal control processes. In addition, the Board of Statutory Auditors, acting as the Internal Control and Financial Auditing Committee pursuant to Legislative Decree no. 39/2010 (Consolidate Law on Statutory Audits of annual accounts and consolidated accounts), must satisfy the requirement imposed by Art. 19 of that law, providing that "the members of the internal control and financial auditing committee, as a body, are competent in the sector in which the company being audited operates".

Pursuant to the Consolidated Law on Financial Intermediation, the Board of Statutory Auditors monitors: (i) compliance with the law and the Company's By-laws; (ii) observance of the principles of sound administration; (iii) the appropriateness of the Company's organizational structure for matters within the scope of the Board's Authority, the adequacy of the internal control system and the administrative and accounting system and the reliability of the latter in accurately representing the Company's transactions; (iv) the procedures for implementing the Corporate Governance rules provided for in the Corporate Governance Code, which the Company has adopted; and (v) the adequacy of the instructions imparted by the Company to its subsidiaries, in order to guarantee full compliance with legal reporting requirements.

In addition, pursuant to Article 19 of Legislative Decree No. 39/2010, in its role as the "internal control and financial auditing committee" the Board of Statutory Auditors: a) informs the Board of Directors of the conclusion of the statutory audit and transmits to the Board the "additional report" of the audit firm adding proper evaluation if deemed necessary; b) oversees the financial reporting process and presents recommendations to ensure its integrity; c) controls the effectiveness of internal quality control system and Risk Management, the effectiveness of internal audit, with reference to the financial reporting process, without violating its independence; d) oversees the statutory audit of annual accounts and consolidated accounts, also considering results of quality control of the audit activity performed by the public authority responsible for regulating the Italian financial markets; e) verifies and monitors the independence of the audit Firm with particular reference to non-audit services; f) is responsible of the procedure to select the audit Firm, making a recommendation to the Shareholders' Meeting for the appointment of the audit Firm.

The responsibilities assigned under the Legislative Decree No. 39/2010 to the "internal control and financial auditing committee" are consistent and substantively in line with the duties already assigned to the Board of Statutory Auditors of Eni, with specific consideration of its role as Audit Committee pursuant to the "U.S. Sarbanes-Oxley Act" (discussed in greater detail below).

In accordance with law, the Board of Statutory Auditors presents the results of its supervisory activity in a report to the Shareholders Meeting. This report is made available in its entirety to the public within the time limits applicable to the Financial Statements.

On March 22, 2005, the Board of Directors, electing the exemption granted by the U.S. Securities and Exchange Commission applicable to foreign issuers listed on the regulated U.S. markets, designated the Board of Statutory Auditors as the body that, as of June 1, 2005, would perform, to the extent permitted under Italian regulations, the functions attributed to the Audit Committee of foreign issuers by the

Sarbanes-Oxley Act and U.S. SEC rules. On June 15, 2005, the Board of Statutory Auditors approved the internal rules, later updated, concerning its performance of the duties assigned to it under that U.S. legislation, the text of which is available on Eni's website. The key functions performed by the Board of Statutory Auditors acting as an audit committee as provided for by U.S. SEC include:

- evaluating the offers submitted by external Auditors for their engagement and providing a reasoned recommendation to the Shareholders' Meeting concerning the engagement or removal of the external Auditor;
- overseeing the work of the external Auditor engaged to audit the accounts or perform other audit, review or certification services;
- examining the periodical reports from the external auditor relating to: a) all critical accounting policies and practices to be used; b) all alternative treatments of financial information within generally accepted accounting principles that have been discussed with management officials of the Company, ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditor; and c) other material written communication between the external auditor and management;
- making recommendations to the Board of Directors on the resolution of disagreements between management and the auditor regarding financial reporting.

In addition the Board of statutory auditor:

- approves the procedures for: a) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters;
- examines reports from the CEO and the CFO concerning: i) any significant deficiency in the design or operation of internal controls which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information and any material weakness in internal controls; and ii) any fraud that involves management or other employees who have a significant role in the Company's internal controls.

The Board of Statutory Auditors, in the performance of its duties, is supported by Company's departments, in particular the Internal Audit Department and the Administrative and Financial Statement Department.

Eni Watch Structure and Model 231

In accordance with the Italian regulations concerning the "administrative liability of legal entities deriving from criminal offences", contained in Legislative Decree No. 231 of June 8, 2001 (henceforth, "Legislative Decree No. 231/2001"), legal entities, including corporations, may be held liable – and consequently fined or subject to prohibitions – in relation to certain crimes attempted or committed in Italy or abroad in the interest or for the benefit of the Company by individuals in high-ranking positions and/or persons managed or supervised by an individual in a high ranking position. The companies may, in any case, adopt organizational, management and control models designed to prevent these crimes. With respect to this issue, Eni Board of Directors – in its Meetings of December 15, 2003 and January 28, 2004 – approved an organizational, management and control model pursuant to Legislative Decree No. 231 of 2001 (Model 231) and created the Watch Structure. Moreover, as a result of changes in the Italian legislation governing the matter and of the Company's organizational structures, on March 14, 2008, the Board of Directors updated Model 231 and adopted Eni's Code of Ethics – replacing the previous version of the Eni Code of Conduct of 1998 – which represents a clear definition of the value system that Eni recognizes, accepts and upholds and the responsibilities that Eni assumes internally and externally in order to ensure that all business activities are conducted in compliance with laws, in a context of fair competition, with honesty, integrity, correctness and in good faith, respecting the legitimate interests of all stakeholders with which Eni relates on an ongoing basis. These include shareholders, employees, suppliers, customers, commercial and financial partners, and the local communities and institutions of the countries where Eni operates. Since its first adoption, Model 231 has been updated very frequently, in most cases in response to new provisions of law coming into force as well as to organizational changes in the company's structure. Most recently, the Board of Directors, in its meeting of November 23, 2017 approved the updating of Model 231 and Eni's Code of Ethics.

The synergies between the Code of Ethics – an integral part and essential general principle of Model 231 – and Model 231 are highlighted by the assignment, to the Eni Watch Structure, of the function of Guarantor of the Code of Ethics. At present, the Watch Structure of Eni is composed of three external members, including the Chairman, and four internal members. The internal members are Company executives in charge of Legal Affairs, labor law matters and disputes, Internal Audit and Integrated Compliance. External members are independent professionals, experts in law and/or economic matters. Also in order to grant the Watch Structure the greatest extent of autonomy and independence, the set of rules adopted by the Watch Structure provide for specific quorum to convene and to pass resolutions so to ensure that all resolutions are effectively adopted with the favourable vote of the majority of the external members.

Audit Firm

The auditing of the Company's accounts is entrusted, in accordance with the law, to an independent Audit Firm appointed by the Shareholders' Meeting on the basis of a reasoned recommendation of the Board of Statutory Auditors.

In addition to the obligations set forth in national auditing regulations, Eni's listing on the New York Stock Exchange requires that the Audit Firm issue a report on the Annual Report on Form 20-F, in compliance with the auditing principles generally accepted in the United States. Moreover, the Audit Firm is required to issue an opinion on the efficacy of the internal control system applied to financial reporting.

For the most part, the subsidiaries' financial statements are subject to auditing by Eni's Audit Firm. Moreover, Eni's Audit Firm, for the purpose of issuing an opinion on the Consolidated Financial Statements, assumes responsibility for the auditing activities performed by other audit firms with respect to subsidiaries' financial statements, which, taken together, account for an immaterial share of consolidated assets and revenues.

Acting on the Board of Statutory Auditors' reasoned proposal, the Shareholders' Meeting of April 29, 2010 appointed EY SpA for the financial years 2010-2018[9].

Court of Auditors (Corte dei conti)

The financial management of Eni is subject to the control of the Court of Auditors in order to preserve the integrity of the public finances. This task has been carried out by the Magistrate of the Court of Auditors, Adolfo Teobaldo De Girolamo, appointed by the Presidential Council of the Court of Auditors on December 22, 2014, until February 28, 2019

As from March 1, 2019 the task is performed by the Magistrate of the Court of Auditors Manuela Arrigucci, on the basis of the resolution approved on December 18-19, 2018 by the Presidential Council of the Court of Auditors.

The Magistrate of the Court of Auditors attends the meetings of the Board of Directors, the Board of Statutory Auditors and the Control and Risk Committee.

Employees

As of December 31, 2018, Eni had a total of 31,701 employees, with a decrease of 1,233 employees, down by 3.7% compared to December 31, 2017, which mainly reflects a decrease of 1,362 employees working outside Italy.

The reduction of personnel headcount is mainly due to slight efficiency actions and other strategic operations. The most significant ones are: the disposal of 98,99% of Tigáz Zrt to MET Holding AG, aimed at the completion of the exit from the gas sector in Hungary in line with its disposals and asset rationalization plan started in 2016 and the deconsolidation of Eni Norge's assets linked to the Vår Energi operation.

[9] On the basis of a reasoned proposal presented by the Board of Statutory Auditors, the Shareholders' Meeting of May 10, 2018 approved the engagement of PricewaterhouseCoopers SpA to perform the statutory audit of the accounts of Eni SpA and to audit the internal control system over financial reporting pursuant to US law for the period 2019 – 2027.

Employees at year end

	2018	2017	2016
		(number)	
Exploration & Production	11,645	11,970	12,494
Gas & Power	3,040	4,313	4,261
Refining & Marketing and Chemicals	11,136	10,916	10,858
Corporate and Other activities	5,880	5,735	5,922
	31,701	**32,934**	**33,536**

The table below sets forth Eni's employees as of December 31, 2016, 2017 and 2018 in Italy and outside Italy:

		2018	2017	2016
			(number)	
Exploration & Production	Italy	4,531	4,510	4,608
	Outside Italy	7,114	7,460	7,886
		11,645	11,970	12,494
Gas & Power	Italy	2,089	2,282	2,032
	Outside Italy	951	2,031	2,229
		3,040	4,313	4,261
Refining & Marketing and Chemicals	Italy	8,740	8,580	8,577
	Outside Italy	2,396	2,336	2,281
		11,136	10,916	10,858
Corporate and other activities	Italy	5,642	5,501	5,693
	Outside Italy	238	234	229
		5,880	5,735	5,922
Total	Italy	21,002	20,873	20,910
	Outside Italy	10,699	12,061	12,626
		31,701	**32,934**	**33,536**
of which senior managers		*1,016*	*1,012*	*1,036*

We seek to maintain constructive relationship with labor unions.

Share ownership

As of March 9, 2019, the cumulative number of shares owned by Eni's Directors, Statutory Auditors and Senior Managers was 302,584 less than 0.1% of Eni's share capital outstanding as of the same date. Eni issues only ordinary shares, each bearing one-vote right; therefore shares held by those persons have no different voting rights. The breakdown of share ownership for each of those persons is provided below.

Name	Position	Number of shares owned
Board of Directors		
Emma Marcegaglia	Chairman	87,010(1)
Claudio Descalzi	CEO	39,455
Board of Statutory Auditors		**none**
Senior Managers		**176,119(2)**

(1) Of which No. 597 shares held under Asset Management, No. 7,143 shares held under Asset Management jointly a third person, and No. 45,000 shares held as maked owner joyntly with a third person.

(2) Of which No. 14,390 shares owned by spouses not legally separated and by underage children.

Item 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

Major Shareholders

The Ministry of Economy and Finance controls Eni as a result of the shares directly owned and those indirectly owned through Cassa Depositi e Prestiti SpA (CDP), in which the Ministry of Economy and Finance holds a 82.77% stake.

As of March 9, 2019, the total amount of Eni's voting securities owned by these shareholders was:

Title of class	Number of shares owned	Percent of class
Ministry of Economy and Finance	157,552,137	4.34
Cassa Depositi e Prestiti SpA	936,179,478	25.76

The following table shows the percentage of Eni's share capital owned, either directly or indirectly, by persons that as of March 9, 2019 have notified that their holding exceeds the threshold of 3% pursuant to Article 120 of the Legislative Decree No. 58/1998 (as amended by article 1 of Legislative Decree No. 25 of February 15, 2016) and to the Consob Regulation No. 11971/1999 (as amended by Consob Resolution No. 19614 of May 26, 2016).

Title of class	Percent of class
none	none

Law Decree No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012, modified Italian legislation governing the special powers of the Italian State to comply with European rules. See "Item 10 – Additional information – Limitations on changes in control of the Company (Special Powers of the Italian State)". As of March 22, 2019, there were 38,029,686 ADRs outstanding, each representing two Eni ordinary shares, corresponding to approximately 2.1% of Eni's share capital. See "Item 9 – The offer and the listing".

Related party transactions

In the ordinary course of its business, Eni enters into transactions concerning the exchange of goods, provision of services and financing with associates, joint ventures, joint operations or other affiliates, as well as other companies owned or controlled by the Italian Government. All such transactions are conducted on an arm's length basis and in the interest of Eni Group companies.

Amounts and types of trade and financial transactions with related parties and their impact on consolidated earnings and cash flow, and on the Group's assets and financial condition are reported in "Item 18 – Note 36 of the Notes on Consolidated Financial Statements".

Item 8. FINANCIAL INFORMATION

Consolidated Statements and other financial information

See “Item 18 – Financial Statements”.

Legal proceedings

Eni is a party to a number of civil actions and administrative arbitral and other judicial proceedings arising in the ordinary course of business. Based on information available to date, and taking into account the existing risk provisions disclosed in Note 20 to the Consolidated Financial Statements and that in some instances it is not possible to make a reliable estimates of contingency losses, Eni believes that these legal proceedings will likely not have a material adverse effect on Eni’s Consolidated Financial Statements.

For a description of legal proceedings in which Eni is involved and which may affect Eni’s financial position and results of operations see “Item 18 – Note 27 of the Notes on Consolidated Financial Statements”.

Dividends

Eni is committed to a progressive dividend policy that is linked to expected future growth in earnings and cash flow. For the year 2019 management is planning to distribute a full-year dividend of €0.86 per share, up by approximately 3.6% vs. 2018. The Company’s dividend policy going forward and the sustainability of the dividends that the Company is planning to distribute over the next four years will depend upon a number of factors including achievement of the Company’s industrial targets, future levels of profitability and cash flow provided by operating activities, a sound balance sheet structure, capital expenditures and development plans, in light of the oil price and exchange rate assumptions adopted by management and other planning assumptions described in “Item 5 – Management’s expectations of operations”. The parent company’s net profit and, therefore, the amounts of earnings available for the payment of dividends will also depend on the level of dividends received from Eni’s subsidiaries. In future years, management expects to continue paying interim dividends for each fiscal year, with the balance for the full-year dividend paid in the following year. For further information on the Company’s dividend policy see “Item 5 – Management’s expectations of operations.”

The expectations described above are subject to risks, uncertainties and assumptions associated with the oil&gas industry, and economic, monetary and political developments in Italy and globally that are difficult to predict. For further details see “Item 3 – Risk factors”.

At the General Shareholders’ Meeting scheduled on May 14, 2019, management intends to propose the distribution of a dividend of €0.83 per share for fiscal year 2018, of which €0.42 paid as interim dividend in September 2018.

Total cash outlay for the 2018 final dividend is expected at approximately €1.48 billion (whereas €1.5 billion were distributed in September 2018) if the General Shareholders’ Meeting approves the annual dividend.

Significant changes

See “Item 5 – Recent developments” for a discussion of significant subsequent business developments and transactions occurred after the closing date up to the latest practicable date.

Item 9. THE OFFER AND THE LISTING

Offer and listing details

The principal trading market for the ordinary shares of Eni SpA (Eni), without indication of par value (the "Shares"), is the Mercato Telematico Azionario (Electronic Share Market or "MTA"). MTA, which is the principal trading market for shares in Italy, is a regulated market organized and managed by Borsa Italiana SpA (Borsa Italiana). Eni's American Depositary Receipts (ADRs), each representing two Shares, are listed on the New York Stock Exchange.

The table below sets forth the reported high and low reference prices of Shares on MTA and of ADRs on the New York Stock Exchange, respectively.

	MTA		New York Stock Exchange	
	High	Low	High	Low
	(euro per share)		(U.S.$ per ADR)	
Year ended December 31,				
2014	20.410	13.290	55.300	32.810
2015	17.430	13.140	39.290	29.280
2016	15.470	10.930	33.330	25.000
2017	15.720	12.960	34.090	29.540
2018	16.764	13.330	40.090	30.000
Year ended December 31,				
2017				
First quarter	15.720	14.120	33.260	30.070
Second quarter	15.240	13.160	33.900	30.060
Third quarter	14.000	12.960	33.080	29.540
Fourth quarter	14.720	13.690	34.090	31.870
2018				
First quarter	14.960	13.330	37.390	33.030
Second quarter	16.764	14.432	40.090	34.740
Third quarter	16.610	15.726	39.060	35.500
Fourth quarter	16.376	13.520	37.890	30.000
2019				
First quarter	15.890	13.780	36.170	31.500
Month of				
October 2018	16.376	14.722	37.890	33.170
November 2018	15.634	14.060	35.940	31.960
December 2018	14.512	13.520	33.210	30.000
January 2019	14.806	13.780	33.880	31.500
February 2019	15.288	14.516	34.760	33.000
March 2019	15.890	14.968	36.170	33.720

Since June 27, 2017, Citibank N.A. (the "Depositary") functions as depositary bank issuing ADRs pursuant to a deposit agreement (the "Deposit Agreement") among Eni, the Depositary and the beneficial owners ("Beneficial Owners") and registered holders from time to time of the ADRs issued hereunder.

As of March 22, 2019, there were 38,019,686 ADRs outstanding, representing 76,059,372 ordinary shares or approximately 2.1% of all Eni's shares outstanding, held by 93 holders of record (including the Depository Trust Company) in the United States, 92 of which are U.S. residents. Since certain of such ADRs are held by nominees, the number of holders may not be representative of the number of Beneficial Owners in the United States or elsewhere.

The Shares are included in the FTSE MIB Index (the "FTSE MIB"), the primary benchmark index for the Italian Stock Exchange. Capturing approximately 80% of the domestic market capitalization, the FTSE MIB measures the performance of 40 highly liquid, leading companies across leading industries listed on

MTA and the Investment Vehicles Market (MIV) and seeks to replicate the broad sector weights of the Italian Stock Exchange. The constituents of the FTSE MIB are selected based on market capitalization of free float shares and liquidity. The FTSE MIB is market cap-weighted after adjusting constituents for free float and foreign ownership limits. FTSE MIB is the principal indicator used to track the performance of the Italian Stock Exchange and is the basis for future and option contracts traded on the Italian Derivatives Market (IDEM) managed by Borsa Italiana. The Shares are a component of the FTSE MIB, with a weighting of approximately 12%, as established by FTSE Russel after the quarterly rebalancing for FTSE MIB effective March 18, 2019.

A two-day rolling cash settlement applies to all trades of equity securities on Borsa Italiana. Besides Shares traded on MTA, futures and options contracts on the Shares are traded on IDEM and securitized derivatives based on the Shares are traded on the multilateral trading facility of securitised derivatives financial instruments, organised and managed by Borsa Italiana (SeDeX). IDEM facilitates the trading of futures and options contracts on index and shares issued by companies that meet certain required capitalization and liquidity thresholds. SeDeX is the Borsa Italiana electronic multilateral trading facility where it is possible to trade securitized derivatives (for instance, covered warrants and certificates).

Borsa Italiana disseminates daily market data and news for each listed security, including volume traded and high and low prices. At the end of each trading day an "official price", calculated as the weighted average price of the total volume of each security traded in the market during the session without taking into account the contracts concluded with cross trades and block trades, and a "reference price", calculated as the closing auction price, are reported by Borsa Italiana. For the purposes of the automatic control of the regularity of trading on MTA, the following price variation limits shall apply to contracts concluded on shares making up the FTSE MIB, effective March 11, 2019: (i) ± 5.0% (or such other amount established by Borsa Italiana in the "Guide to the Parameters" for trading on the regulated markets organized and managed by Borsa Italiana) with respect to the static price (the static price shall be the previous day's reference price, in the opening auction, or the auction price, in the continuous trading phase); and (ii) ± 3.5% (or such other amount established by Borsa Italiana in the "Guide to the Parameters") with respect to the dynamic price (the price of the last contract concluded during the continuous trading phase). Where the price of a contract that is being concluded exceeds one of the price variation limits referred to above, trading in that security will be automatically suspended and a volatility auction phase begun for a certain period of time.

Markets

Consob is the public authority responsible for regulating and supervising the Italian securities markets to, inter alia, ensure the transparency and regularity of the dealings and protect the investing public. Borsa Italiana, which is part of London Stock Exchange Group, following the merger effective October 1, 2007, is a joint stock company authorized by Consob to operate, inter alia, regulated markets in Italy; it is responsible for the organization and management of the Italian Stock Exchange. One of the fundamental characteristics of the financial market organization in Italy is the separation of responsibility for supervision (Consob and the Bank of Italy) from that of market management (Borsa Italiana). Main responsibilities of Borsa Italiana are the admission, exclusion and suspension of financial instruments and intermediaries to and from trading and the surveillance of the markets.

According to Consob regulations, Borsa Italiana has issued rules governing the organization and management of the Italian Regulated Markets it is responsible for, which, inter alia, are MTA (for example, shares, convertible bonds, pre-emptive rights, warrants), ETFplus (for example, Exchange Traded Funds, Exchange Traded Commodities, Exchange Traded Notes, Structured ETFs and Actively managed ETFs), IDEM (futures and options contracts whose underlying assets are financial instruments, interest rates, foreign currencies, goods or related indexes),, MOT (bond market) and MIV (market for investment vehicles), as well as the admission to listing on and trading on these markets.

According to the regulatory framework introduced by Markets in Financial Instruments Directive No. 2014/65/EU as amended ("MiFID II"), as implemented in Italy, and Regulation (EU) No. 600/2014 ("MiFIR"), applicable from January 3, 2018, and Consob regulations, orders can be routed not only to Regulated Markets but also to either Multilateral Trading Facilities (MTFs) or Systematic Internalisers. A MTF is a multilateral system, operated by an investment firm or a market operator, which brings together multiple third-party buying and selling interests in financial instruments – in the system and in accordance with non-discretionary rules – in a way that results in a contract. A Systematic Internaliser is an investment firm which, on an organized, frequent systematic and substantial basis, deals on own account when executing client orders outside a Regulated Market, an MTF or an Organized Trading Facility ("OTF") without operating a multilateral system. Following the transposition in Italy of MiFID II and the application of MiFIR, OTFs are now included among the "trading venues" that are subject to regulation. An OTF is a multilateral system which is not a Regulated Market or an MTF and in which multiple third-party buying and selling interests in bonds, structured finance products, emission allowances or derivatives are able to interact in the system in a way that results in a contract.

According to Legislative Decree No. 58 of February 24, 1998, as amended from time to time ("Decree No. 58", the Consolidated Law on Financial Intermediation), the provision of investment services and activities to the public on a professional basis is, inter alia, reserved to investment firms, EU investment companies, Italian banks, EU banks and companies of non-EU countries ("authorized persons"). The Bank of Italy and Consob shall exercise supervisory powers over authorized persons. They shall each supervise the observance of regulatory and legislative provisions according to their respective responsibilities. In particular, in connection with the pursuance of the safeguarding of faith in the financial system, the protection of investors, the stability and correct operation of the financial system, the competitiveness of the financial system and the observance of financial provisions, the Bank of Italy shall be responsible for risk containment, asset stability and the sound and prudent management of intermediaries whilst Consob shall be responsible for the transparency and correctness of conduct. Besides, for the purposes of the application of certain provisions of MiFIR the Bank of Italy and Consob are the Italian competent authorities: Consob is competent, inter alia, as far as the protection of the investors, the orderly functioning and soundness of the financial markets or of the commodity markets are concerned whereas the Bank of Italy is competent as far as the stability of the whole or part of the financial system is concerned.

The Bank of Italy and Consob also regulate the operation of the clearing and settlement service for transactions involving financial instruments as well as the performance of central securities depository services, in line with the European framework – in particular, the Regulation (EU) No. 648/2012, as amended from time to time, ("EMIR") and the Regulation (EU) No. 909/2014, as amended from time to time, ("Central Securities Depositories Regulation"). The regulations and measures of general application adopted by Consob and the Bank of Italy are available on the website of Consob (www.consob.it) or Bank of Italy (www.bancaditalia.it).

The regulations adopted by Borsa Italiana are available on its website (www.borsaitaliana.it).

Item 10. ADDITIONAL INFORMATION

Memorandum and Articles of Association

Company register

"Eni SpA" is the company resulting from the privatization of Ente Nazionale Idrocarburi, a public agency, established by Law No. 136 of February 10, 1953 and it is registered in the Rome Companies Register, with identification number (and tax number) 00484960588, and VAT number 00905811006. The Company's registered office is in Rome, Italy, and the Company has two branch offices in San Donato Milanese (Milan).

The full text of Eni's By-laws is attached as an exhibit to this Annual Report (last amended on November 20, 2014). See "Exhibit 1".

Company objects and purpose

In accordance with Article 4 of Eni's By-laws, the Company purpose includes the direct and/or indirect exercise, through equity holdings in companies or other entities of: activities in the field of hydrocarbons and natural gases, in compliance with the terms of concessions provided for by law; activities in the field of chemicals, nuclear fuels, geothermal energy, renewable energy sources and energy in general, in the design and construction of industrial plants, in the mining industry, in the metallurgy industry, in the textile machinery industry, in the water sector, including water diversion, potabilization, purification, distribution and reuse; in the environmental protection sector and in the treatment and disposal of waste, as well as any other economic activity that is instrumental, ancillary or complementary to the aforementioned activities. The Company performs and manages the technical and financial coordination of subsidiaries and associated companies and provides financial assistance to them. Moreover, the Company may acquire equity holdings and interests in other companies or enterprises with corporate purposes that are similar, related or complementary to its own or those of companies in which it has equity holdings, either in Italy or abroad, and it may provide secured and/or unsecured guarantees for its own and others' obligations, including, in particular, sureties.

Directors' issues

Eni's Board of Directors is invested with the fullest powers for the ordinary and extraordinary management of the Company and, in particular, the Board has the power to perform all acts it deems advisable for the implementation and achievement of the corporate purpose, with the sole exception of acts that the law or Eni's By-laws reserve to the Shareholders' Meeting.

If the Shareholders' Meeting has not appointed a Chairman of the Board, the Board shall elect one from among its members.

The Board of Directors appoints a Chief Executive Officer and delegates to him all necessary powers for the management of the Company, with the exception of those powers that cannot be delegated in accordance with current legislation and those retained exclusively by the Board of Directors on matters regarding major strategic, operational and organizational decisions.

According to Eni's By-laws, the Board of Directors may delegate powers to the Chairman to identify and promote integrated projects and international agreements of strategic importance.

The Board of Directors may at any time revoke the powers delegated, proceeding, in the case of revocation of the powers delegated to the Chief Executive Officer, to appoint another Chief Executive Officer at the same time.

The Board of Directors, acting upon a proposal of the Chairman and in agreement with the Chief Executive Officer, may confer powers for individual acts or categories of acts on other members of the Board of Directors.

In accordance with Eni's By-laws, for a Board meeting to be valid, a majority of serving Directors must be present. Resolutions shall be approved by a majority of the votes of the Directors present; in the event of a tie, the person who chairs the meeting shall have a casting vote.

For further information on Directors' duties and responsibilities and, in particular, the role of the Chairman see "Item 6 – Board of Directors' duties and responsibilities".

Interests in Company's transactions

As provided by the Italian Civil Code, when a Director retains a personal interest or an interest on behalf of third parties in Company transactions, he shall disclose it to the Board of Directors and to the Board of Statutory Auditors, specifying the nature, terms, origin and extent of such interest. Based on this provision and in compliance with the Consob ("Commissione Nazionale per le Società e la Borsa" is the public authority responsible for regulating the Italian financial markets) regulation on transactions with related parties (the "Consob Regulation"), the Board of Directors – on November 18, 2010 – unanimously approved the Management System Guidelines "Transactions involving interests of Directors and Statutory Auditors and transactions with related parties"[1] ("MSG"), which has been in effect from January 1, 2011[2] to ensure the transparency and substantial and procedural fairness of transactions with related parties and with parties that are of interest to Eni's Directors and Statutory Auditors, carried out by Eni itself or its subsidiaries. This MSG and the subsequent amendments received the preliminary favorable opinion, expressed unanimously, of the Control and Risk Committee, composed entirely of independent Directors as per the requirements set out in the Corporate Governance Code, which Eni has adopted, and in

(1) The Board of Directors modified this Management System Guideline on January 19, 2012 and lastly on April 4, 2017.

(2) This MSG replaced the previous regulation issued by the Board of Directors on the matter on February 12, 2009. The new provisions regarding information to be provided to the public, under both the Consob Regulation and the MSG, have been applied since December 1, 2010.

accordance with the Consob Regulation. The MSG sets out monitoring and evaluation requirements for the preliminary phase and for carrying out a transaction with a party in which a Director or Statutory Auditor has an interest. In this regard, both in the preliminary and deliberation phase, a thorough, documented examination of the reasons for the transaction, highlighting the Company's interest in carrying it out and the soundness and fairness of the underlying terms, is required. Directors involved in matters subject to Board resolution normally shall not participate in the relevant discussion and decision and shall leave the room during these procedures. If the person involved is the Chief Executive Officer and the transaction falls under his duties, he shall in any case abstain from taking part in the transaction and shall entrust the matter to the Board of Directors (as provided by Article 2391 of the Italian Civil Code). In any case, if the transaction is under the responsibility of the Board of Directors of Eni, a non-binding opinion from the Control and Risk Committee is required.

Moreover, to ensure compliance with the procedures envisaged by the above mentioned MSG, Directors and Statutory Auditors issue a declaration, every six months and/or when there is any change, in which they state their potential interests related to Eni and its subsidiaries. In any case the Directors and the Statutory Auditors report in good time the single transactions that Eni intends to carry out in which they have an interest. Directors report the interest to the Chief Executive officer (or the Chairman, in the case of interests of the Chief Executive Officer), who will in turn notify the other Directors and the Board of Statutory Auditors. Statutory Auditors report the interest to the other Statutory Auditors and the Chairman of the Eni SpA Board of Directors.

Compensation

Directors' compensation shall be determined by the Shareholders' Meeting, as required by Italian law, while the compensation of Directors with delegated powers in accordance with the By-laws (such as the Board Chairman and the CEO), or that participate in Board Committees, shall be determined by the Board of Directors, upon the proposal of the Remuneration Committee, after examining the opinion of the Board of Statutory Auditors (for more details about the compensation policy in 2018, see the Remuneration Report 2019 incorporated herein by reference).

Borrowing powers

The power to borrow is included in the Company purpose. Moreover, in accordance with Article 11 of the By-laws, the Company may issue bonds, including convertibles bonds and warrants, in compliance with the law.

Retirement and shareholdings

There are no provisions in the By-laws relating to either retirement based on age-limit requirements and the number of shares required for a Director to qualify.

Company's shares

In accordance with Article 5 of the By-laws, the Company's share capital amounts to €4,005,358,876.00, fully paid, and is represented by 3,634,185,330 ordinary registered shares without indication of par value. As required by the Italian law on the dematerialization of financial instruments, Eni's shares (the "Shares") must be held with "Monte Titoli SpA" (the Italian Central Securities Depository) and their beneficial owners may exercise their rights through special deposit accounts opened with intermediaries, such as banks, brokers and securities dealers.

Shares are indivisible and each share is entitled to one vote. Shareholders are allowed to vote at ordinary and extraordinary Shareholders' Meeting, including by proxy or by mail or, if envisaged in the notice calling the Meeting, by electronic means.

Moreover, in accordance with Article 9 of the By-laws, the Shareholders' Meeting may resolve to increase the Company share capital by issuing shares, including shares of different classes, to be granted for no consideration to Eni employees, pursuant to Article 2349 of the Italian Civil Code. This power has not been exercised.

In 1995, Eni established a sponsored American Depositary Receipts program directed at U.S. investors.

Each Eni ADR is equal to two Eni ordinary shares; Eni ADRs are listed on the NYSE.

Dividend rights

Shareholders have the right to participate in profits and any other rights as provided by the law and subject to any applicable legal limitations. Specifically, the ordinary Shareholders' Meeting called to approve the annual Financial Statements may allocate the net income resulting after allotment to the legal reserve to the payment of a final dividend per share. In addition, during the course of the financial year, the Board of Directors may distribute, as allowed by the By-laws, interim dividends to the shareholders. Entitlement to dividends not collected within five years of the day on which they become payable shall lapse in favor of the Company and such dividends shall be allocated to reserves.

Voting rights

The general provisions on share "voting rights" are described at the paragraph "Shareholders' Meeting" below. In relation to the appointment of the Board of Directors (Eni's Board is not a "staggered board") and the Board of Statutory Auditors (see "Item 6"), Eni's By-laws provide for a slate voting system. In particular, pursuant to Article 17 of the By-laws and in accordance with applicable law, slates may be presented both by shareholders, either severally or jointly, representing at least 1% of the share capital, or any other threshold established by Consob in its regulation (lastly, on January 24, 2019, Consob confirmed a threshold of 0.5% for Eni, given its market capitalization), or by the Board of Directors. Each shareholder may, severally or jointly, submit and vote on a single slate only.

There are no provisions in Eni's By-laws relating to: rights to share in Company profits; redemption provisions; sinking fund provisions; liability to further capital calls by the Company.

Liquidation rights

In the event the Company is wound up, the Shareholders' Meeting shall decide the manner of its liquidation and appoint one or more liquidators, establishing their powers and remuneration. In accordance with Italian law, shareholders would be entitled to the distribution of the remaining liquidated assets of the Company in proportion to their shareholdings, only after payment of all the Company's liabilities and satisfaction of all other creditors.

Change in shareholders' rights

A shareholders' resolution is required to make changes in shareholders' rights. Italian law gives shareholders the right to withdraw in the event of an amendment of the provisions of the By-laws relating to, among other matters, voting and dividend rights, approved by resolution of the Shareholders' Meeting with the attendance and decision making quorum established by law for extraordinary meetings.

Shareholders' Meeting

The Shareholders' Meeting resolves on the issues set forth by applicable law and Eni's By-laws, in "ordinary" or "extraordinary" form. The ordinary and the extraordinary Shareholders' Meetings are normally held after a single call, with the majorities required by law in this case. The Board of Directors may, if deemed necessary, establish that both the ordinary and the extraordinary Shareholders' Meetings shall be held after more than one call; their resolutions at first, second or third call must be passed with the majorities required by law in each case.

Shareholders' Meetings shall normally be held at the Company's registered office, unless otherwise decided by the Board of Directors, provided however they are held in Italy.

The Shareholders' Meeting shall be called by way of a notice published on the Company website, as well as in accordance with the procedures specified in Consob regulations, by the statutory deadlines and in accordance with applicable law. The notice calling the meeting, the content of which is defined by the law and Eni's By-laws, contains all the information for attending and voting at the meeting, including information on proxy voting and voting by mail (the information is also available on the Company's website) and, if envisaged, it may include instructions for participating in the Shareholders' Meeting by means of telecommunication systems, as well as exercising the right to vote by electronic means. The Board of Directors shall make a report on each of the items on the agenda available to the public at the Company's registered office, on the Company's website and by other means envisaged by Consob regulations by the same date of the publication of the notice calling the Shareholders' Meeting for each of the items on the agenda. Specific legal provisions may require other terms of publication of the Board of Directors report (i.e. in case of extraordinary transactions). An ordinary Shareholders' Meeting shall be called at least once a year, within 180 days of the end of the Company's financial year (on December 31), to approve the financial statements, since the Company is required to draw up Consolidated Financial Statements.

The right to attend and cast a vote at the Shareholders' Meeting shall be certified by a statement submitted by an authorized intermediary on the basis of its accounting records to the Company on behalf of the person entitled to vote. The statement shall be issued by the intermediary on the basis of the balances on the accounts recorded at the end of the seventh trading day prior to the date of the Shareholders' Meeting. Credit and debit records entered on the authorized intermediaries' accounts after this deadline shall not be considered for the purpose of determining entitlement to exercise voting rights at the Shareholders' Meeting. The statement, issued by the authorized intermediary, must reach the Company by the end of the third trading day prior to the date of the Shareholders' Meeting, or by any other deadline established by Consob regulations issued in agreement with the Bank of Italy. Shareholders shall nevertheless be entitled to attend the Meeting and cast a vote if the statements are received by the Company after the deadlines indicated above, provided they are received before the start of proceedings of the given call. For the purposes of these provisions, reference is made to the date of first call, provided that the dates of any subsequent calls are indicated in the notice calling the Meeting; otherwise, the date of each call is deemed the reference date.

Those persons who are entitled to vote may appoint a party to represent themselves at the Shareholders' Meeting by means of a written proxy or in electronic form in the manner set forth by current law. Electronic notification of the proxy may be made through a special section of the Company website as indicated in the notice calling the Meeting. In order to simplify proxy voting by shareholders who are employees of the Company or of its subsidiaries and belong to shareholders' associations that meet applicable statutory requirements, locations for communications and collection of proxies shall be made available in accordance with the terms and conditions agreed from time to time with the legal representatives of said associations.

The right to vote may also be exercised by mail in accordance with the applicable laws and regulations. If provided for in the notice calling the meeting, those persons entitled to vote may participate in the Shareholders' Meeting by means of telecommunication systems and exercise their right to vote by electronic means in accordance with the provisions of the law, applicable regulations and the Shareholders' Meeting Rules.

The Company may designate a person for each Shareholders' Meeting to whom the shareholders may confer a proxy with voting instructions on all or some of the items on the agenda, as provided for by applicable laws and regulations, by the end of the second trading day preceding the date set for the Shareholders' Meeting including for calls subsequent to the first. Such proxy shall not be valid for items in respect of which no voting instructions have been provided.

The Chairman of the meeting shall verify the validity of proxies and, in general, entitlement to participate in the Meeting.

The Shareholders' Meetings are governed by the Shareholders' Meeting Rules as approved by resolution of the ordinary Shareholders' Meeting on December 4, 1998, in order to guarantee an efficient conduct of meetings and the right of each shareholder to express his or her opinion on the items on the agenda.

During Shareholders' Meetings, the Board of Directors provides broad disclosure on items examined and shareholders can request information on issues in the agenda. Information is provided taking into account applicable rules on inside information.

Stock ownership limitation and voting rights restrictions

There are no limitations imposed by Italian law or by Eni's By-laws on the rights of non-residents in Italy or foreign persons to hold shares or vote other than the limitations described below (which are equally applicable to both residents and non-residents of Italy).

In accordance with Article 6 of the By-laws, and in application of the special rules pursuant to Article 3[3] of Decree Law No. 332 of May 31, 1994, ratified with amendments by Law No. 474 of July 30, 1994 (Law No. 474/1994), no shareholder may hold, in any capacity, directly or indirectly, more than 3% of the Company's share capital. Any voting rights and any other non-financial rights attached to shares held in excess of the maximum limit indicated above may not be exercised and the voting rights of each shareholder to whom such limit applies shall be reduced in proportion, unless otherwise jointly specified in advance by the parties involved.

Pursuant to Article 32 of the By-laws and the above mentioned provision of law, shareholdings owned by the Ministry of the Economy and Finance, public entities or organizations controlled by them are exempt from this ban.

Finally, this special rule provides that the clause regarding shareholding limits will lose effect if the limit is exceeded as a result of a take-over bid, provided that, as a result of the takeover, the bidder will own a shareholding of at least 75% of the share capital with the right to vote on resolutions concerning the appointment or dismissal of Directors.

Limitation on changes in control of the Company (Special Powers of the Italian State)

Decree Law No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012 (Law No. 56/2012), modified Italian legislation governing the special powers of the Italian State to comply with European rules[4].

The special powers apply to companies that hold strategic assets vital to the interests of the Italian State as defined by the ministerial regulations which implement the relevant law.

The current legislation governing the special powers briefly include: a) veto power (or the power of imposing conditions or requirements) over transactions involving strategic assets that could result in a situation, not regulated by Italian or EU laws, that threatens serious injury to interests regarding networks and systems security, as well as continuity of supply; and b) power of attaching conditions or opposing the acquisition by an entity outside of the EU of shareholdings that determine the control of a company that holds, directly or indirectly, strategic assets, when such an acquisition may result in a threat of serious injury to the above mentioned essential interests of the Italian State (see also the provisions of Decree Law No. 148 of October 16, 2017, ratified with amendments by Law No. 172 of December 4, 2017, reported below). The shareholding of third parties who have entered into a shareholders' agreement with the buyer is taken into account in the calculation of above mentioned relevant shareholdings.

With particular reference to the power referred to in letter b), the legislation establishes notification obligations for the buyer entity outside of the EU to the Italian Presidency of the Council of Ministers as well as procedural terms. Until such notification and thereafter, up to the expiration of the term for the possible exercise of power, the voting rights and any other non-financial right related to the significant shareholding may not be exercised.

In the case of non-fulfillment of imposed conditions, throughout the relevant period, the voting rights and any other non-financial right related to the significant shareholding may not be exercised. The resolutions adopted with the decisive vote of such shareholding, or otherwise the resolutions or acts adopted in breach or default of the imposed conditions are void. In addition, unless the fact constitutes a crime, failure to comply with imposed conditions entail for the purchaser a fine.

In case of opposition, the buyer may not exercise the voting rights and any other non-financial right related to the significant shareholding, which must be sold within a year. In case of non-compliance, at the request of the Government, the Court will order the sale of the significant shareholding. Shareholders' Meeting resolutions adopted with the decisive vote of such participation shall be void.

(3) This provision has been modified by the Decree Law No. 21 of March 15, 2012, ratified with amendments by Law No. 56 of May 11, 2012. For more details see the paragraph "Limitation on changes in control of the Company (Special Powers of the Italian State)" below.

(4) The prior provisions (Article 2 of Decree Law No. 332/1994, ratified by Law No. 474/1994 and its implementing decrees), as well as the provisions of the By-laws which were inconsistent with the new rules, lapsed at the issuance of Decree of the President of the Italian Republic No. 85 of March 25, 2014, in force since June 7, 2014.

The legislation provides for a general rule that the acquisition, for any reason, by an entity outside of the EU of stock of company that holds strategic assets be allowed on condition of reciprocity, in compliance with international agreements signed by Italy or the EU.

These powers are exercised exclusively on the basis of objective and non-discriminatory criteria.

Decree Law No. 148 of October 16, 2017, ratified with amendments by Law No. 172 of December 4, 2017, extended the special powers of the Italian State to high-technology industries[5]. Furthermore, with regard to investments in companies with strategic assets by a non-EU investor, the decree added two assessment criteria for the exercise of the special powers, namely a threat to security or to public order[6], in addition to safeguarding the essential interests of the State.

Albeit with some amendments, the provisions regarding the stock ownership limitations and voting rights restrictions pursuant to Article 3 of Law No. 474/1994 are still in force.

In order to "promote privatization and the spread of investment in shares" of companies in which the Italian State has a significant shareholding, Article 1, paragraphs 381 to 384 of Law No. 266 of 2005 (2006 Financial Law) introduced the power to add provisions to the By-laws of privatized companies primarily controlled by the Italian State, like Eni, which allow shares or participating financial instruments to be issued that grant the special meeting of its holders the right to request that new shares, even at par value, or new financial instruments be issued to them with the right to vote in ordinary and extraordinary Shareholders' Meetings. Making this amendment to the By-laws would lead to the shareholding limit referred to in Article 6.1 of the By-laws being removed. At the present time, however, Eni's By-laws do not contain any of such provisions.

Shareholder ownership thresholds

There are no By-law provisions governing the disclosure of the ownership threshold because the matter is regulated by Italian law. Pursuant to the Consolidated Law on Finance[7] and the Consob Regulation[8], any direct or indirect holding in the voting shares of an Italian listed company in excess of 3%[9], 5%, 10%, 15%, 20%, 25%, 30%, 50%, 66.6% and 90% must be notified to the investee company and to Consob. The same disclosure requirements refer to holdings that drop below one of the specified thresholds.

Such disclosures shall be made – using the forms contained in Annex 4A to the above Regulation – without delay and, in any case, within four days of the transaction, starting from the day on which the subject gains knowledge of the transaction that can lead to the obligation, regardless of the date of execution, or from the date on which the subject obliged to make the disclosure gains knowledge of the event that leads to changes in the share capital as contemplated in the Consob Regulation.

For the purpose of the above disclosure obligations, the Consob Regulation establishes investment calculation criteria[10]. The obligation to notify also applies to any direct or indirect holding owned through ADRs.

Specific disclosure requirements (with partially different thresholds) are connected to investments in financial instruments and for aggregate investments[11].

Under the above mentioned Decree Law No. 148/2017, in the case of the purchase of a stake in quoted issuers equal or above the thresholds of 10%, 20% and 25% of the relevant share capital in listed companies, the investor shall state the objectives it intends to pursue in the following six months. The

(5) The identification of the high-technology industries is left to one or more implementing government regulations, not yet issued at the date of approval of this Report.

(6) In order to determine if a foreign investment could impact security or public order, Article 2, paragraph 6, of Law no. 56/2012, as updated by Decree-law no. 148/2017, establishes that it is possible to take into consideration the circumstance of a foreign investor being controlled by the government of another non-EU country, including by way of significant financing.

(7) Legislative Decree No. 58 of February 24, 1998, with specific reference to Articles 120-122.

(8) Article 117 of Consob Decision No. 11971/1999 and subsequent amendments.

(9) The Legislative Decree No. 25/2016, in force since March 18, 2016, modified the Article 120 of the Legislative Decree No. 58/1998, increasing this holding threshold from 2% to 3%. Moreover, Consob may, by means of measures justified by the need to protect investors, as well as corporate control market and capital market efficiency and transparency, envisage – for a limited period of time – lower thresholds by its decree for companies with an elevated current market value and particularly extensive shareholding structure.

(10) Article 118 of Consob Decision No. 11971/1999 and subsequent amendments.

(11) Article 119 of Consob Decision No. 11971/1999 and subsequent amendments.

declaration shall state under the responsibility of the declarant: a) the means of financing the acquisition; b) whether acting alone or in concert; c) whether it intends to stop or continue its purchases, and whether it intends to acquire control of the issuer or anyway have an influence on the management of the company and, in such cases, the strategy it intends to adopt and the transactions to be carried out; d) its intentions as to any agreements and shareholders' agreements to which it is party; e) whether it intends to propose the integration or revocation of the issuer's administrative or control bodies. Consob can identify, with its own regulation, the cases where the aforementioned declaration is not due, taking into account the characteristics of the entity making the declaration or of the company whose shares have been purchased.

The declaration shall be transmitted to the company whose shares have been purchased and to Consob and shall be subject to public disclosure in accordance with the terms and conditions established by Consob Regulation.

Voting rights attached to listed shares which have not been notified pursuant to the above mentioned disclosure requirements may not be exercised. Any resolution or act adopted in violation of such limitation, with the contribution of those undisclosed shares, could be voided if challenged in court, under the Italian Civil Code.

According to the Italian Civil Code (Article 2359-*bis*), a subsidiary may acquire shares of the parent company only within the limits of distributable profits and available reserves as resulting from the last approved balance sheet. Only fully-paid shares can be purchased. The purchase must be approved by the Shareholders' Meeting and, in any case, the nominal value of shares purchased may not exceed one-fifth of the capital of the parent company – if the latter is a listed company – taking into account for this purpose the shares held by the same parent company or its subsidiaries.

The Consolidated Law on Finance provides rules governing cross-holdings. In particular, except for the cases contemplated by the above mentioned Article 2359-*bis* of the Italian Civil Code, in case of a reciprocal participation exceeding the limit of 3% of the shares, the company that exceeds the limit successively cannot exercise its right to vote relative to the shares held in excess of such threshold and must sell such shares within the following 12 months. In the event of failure to dispose of the shares by such time limit, the voting rights shall be suspended with respect to the entire shareholding. Where it is not possible to ascertain which of the two companies was the last to exceed the limit, the suspension of voting rights and the disposal requirement shall apply to both unless they have agreed otherwise. In the event of non-compliance, any resolution or act adopted with the contribution of the relevant shares may be challenged under the Italian Civil Code.

The above mentioned limit is increased to 5% (or to 10% if the issuer is a small or medium enterprise as per Article 1, letter w-*quater*.1 of the Consolidated Law on Finance) if the threshold is exceeded by both companies subsequent to an agreement authorized in advance by the ordinary shareholders' meetings of the companies concerned.

If a person holds an interest exceeding the aforementioned threshold of a listed company, such listed company or any person controlling such listed company may not acquire an interest exceeding such a limit in a listed company controlled by the former. In the event of non-compliance, the voting rights attached to the shares in excess of the limit specified shall be suspended. Where it is not possible to ascertain which of the two persons was the last to exceed the limit, the suspension shall apply to both unless they have agreed otherwise. In the event of non-compliance, any resolution or act adopted with the contribution of the relevant shares may be challenged under the Italian Civil Code.

The limitations described above are not applicable in the case of a takeover bid or exchange tender offer to acquire at least 60% of the ordinary shares of a listed company.

Under the Consolidated Law on Finance, any agreement, in any form, regarding the exercise of voting rights in a listed company or in its parent company, must be, within five days of stipulation: (i) notified to Consob; (ii) published in abstract form, in the Italian daily press; (iii) filed with the Register of Companies in which the listed company is registered; and (iv) notified to the company with listed shares. In the event of non-compliance with these requirements, the agreements shall be null and void and the voting rights attached to the relevant shares may not be exercised and any resolution or act adopted with the contribution of such shares may be challenged under the Italian Civil Code.

The same provisions also apply to agreements, in any form, that: (a) create obligations of consultation prior to the exercise of voting rights in a listed company and in its controlling companies; (b) set limits on the transfer of the related shares or of other financial instruments that entitle holders to buy or subscribe them; (c) provide for the purchase of the shares or of the above mentioned financial instruments; (d) have as their object or effect the exercise, jointly or otherwise, of dominant influence on such companies; and (d-*bis*) which aim to encourage or frustrate a takeover bid or an exchange tender offer, including commitments relating to non-participation in a takeover bid.

Finally, pursuant to Law No. 287 of October 10, 1990, any merger or acquisition of (legal or factual) sole or joint control over a company or any change of control over a company is subject to the prior authorization by the Italian Antitrust Authority[12] if the companies involved exceed given turnover thresholds. If the said merger, acquisition or change of control would create or strengthen a dominant position in the Italian market in a manner that eliminates or significantly reduces competition, the Italian Antitrust Authority can either prohibit the transaction or make it subject to remedies preventing a restriction of competition. Moreover, if the transaction or the companies involved exceed other thresholds set by European or other countries' legislations (e.g. other turnover thresholds or thresholds referred to transaction's value or market shares of the parties), the transaction can also be subject to the prior authorization by competition authorities of other jurisdictions.

Changes in share capital

Eni's By-laws do not provide for more stringent conditions than are required by law.

Share capital increases are resolved by a shareholders' resolution at an extraordinary Shareholders' Meeting. Under Italian law, shareholders have a pre-emptive right to subscribe newly issued shares and corporate bonds convertible into shares in proportion to their respective shareholdings. If the Company's interest so requires, the pre-emptive right may be waived or limited by the shareholders' resolution authorizing the share capital increase. The shareholders' pre-emptive right is also waived if the shareholders' resolution authorizing the share capital increase provides for the subscription of new issues of shares in the form of contributions in-kind.

Material contracts

None.

Exchange controls

Under current Italian exchange control regulations, no limits exist on the amount of payments that Eni may remit to residents of the United States. Laws and regulations concerning foreign exchange controls do require, however, that an accredited intermediary must handle all payments or transfer of funds made by an Italian resident to a non-resident.

Taxation

The information set forth below is only a summary; Italian, the United States and other tax laws may change from time to time. Holders of shares and ADRs should consult with their professional advisors as to the tax consequences of their ownership and disposition of the shares and ADRs, including, in particular, the effect of tax laws of any other jurisdiction.

Italian taxation

The following is a summary of the material Italian tax consequences of the ownership and disposition of shares or ADRs as at the date hereof and does not purport to be a complete analysis of all potential tax effects relevant to the ownership or disposition of shares or ADRs.

Income tax

Dividends regarding income of financial year 2018 paid in 2019, received by Italian resident individuals, holding the shares or ADRs in connection with entrepreneurial activity, are included in the

(12) Autorità garante per la concorrenza e il mercato (AGCM – www.agcm.it)

taxable income subject to personal income tax to the extent of 58.14% of their amount. Personal income tax applies at progressive rates ranging from 23% to 43% plus local surtaxes. Dividends received by Italian resident individuals holding the shares or ADRs otherwise than in connection with entrepreneurial activity, are subject to a substitute tax of 26% withheld at the source by the dividend paying agent. This being the case, the dividend is not to be included in the individual's tax return.

Dividends received by Italian investment funds, foreign open-ended investment funds authorized to market their securities in Italy pursuant to the Law Decree June 6, 1956, No. 476, converted into Law July 25, 1956, No. 786, and società di investimento a capitale variabile (SICAV) are not subject to substitute tax but are included in the aggregate income of the investment fund or SICAV. The investment fund or SICAV will not be subject to tax on the dividends. A withholding tax of 26% may apply on income of the investment fund or SICAV derived by unitholders or shareholders through distribution and/or upon redemption or disposal of the units and shares.

Dividends received by real estate funds to which the provisions of Law Decree No. 351 of September 25, 2001, as subsequently amended, apply, are not subject to any substitute tax nor to any other income tax in the hands of the fund. The income of the real estate fund is subject to tax, in the hands of the unitholder, depending on status and percentage of participation, or, when earned by the fund, through distribution and/or upon redemption or disposal of the units.

Dividends received by a pension fund (subject to the regime provided for by Article 17 of the Italian Legislative Decree No. 252 of December 5, 2005) and deposited with an authorized intermediary, will not be subject to substitute tax, but must be included in the result of the relevant portfolio accrued at the end of the tax period, to be subject to a 20% substitute tax.

Dividends paid to non-Italian residents are subject to the same substitute tax levied at source by the dividend paying agent at the rate of 26%, provided that the interest is not connected to an Italian permanent establishment.

Dividends are subject to a 1,20% substitute tax introduced by the Financial Bill for 2008 where the conditions in Article 27, paragraph 3-ter, Presidential Decree No. 600 of 1973 are met, i.e. dividends are paid to companies and entities subject to a corporate income tax in a European Union Member State or in the European Economic Area.

The substitute tax may also be reduced under the Tax Treaty in force between Italy and the country of residence of the Beneficial Owner of the dividend. Italy has executed income Tax Treaties with approximately 90 foreign countries, including all EU Member States, Argentina, Australia, Brazil, Canada, Japan, New Zealand, Norway, Switzerland, the United States and some countries in Africa, the Middle East and the Far East. Generally speaking, it should be noted that Tax Treaties are not applicable where the holder is a tax-exempt entity or, with few exceptions, a partnership or a trust.

In order to obtain the Treaty benefit of a reduced substitute tax rate at the same time of payment, the Beneficial Owner must file an application to the dividend paying agent chosen by the Depositary stating the existence of the conditions for the applicability of the Treaty benefit, together with a certification issued by the foreign tax authorities stating that the shareholder is a resident of that country for Treaty purposes.

Under the Tax Treaty between the United States and Italy, dividends derived and beneficially owned by a U.S. resident who holds less than 25% of the Company's shares are subject to an Italian withholding or substitute tax at a reduced rate of 15%, provided that the interest is not effectively connected with a permanent establishment in Italy through which the U.S. resident carries on a business or a fixed establishment in Italy through which such U.S. resident performs independent personal services (for further details please refer to the relevant provisions set forth in the Italy U.S. Tax Treaty). In the absence of such conditions, the dividend paying agent will deduct from the gross amount of the dividend the substitute tax at the statutory rate of 26%. Based on the certification procedure required by the Italian Tax Authorities, to benefit from the direct application of the 15% substitute tax the U.S. shareholder must provide the dividend paying agent with a certificate obtained from the U.S. Internal Revenue Service (the IRS) with respect to each dividend payment. The request for this certificate must include a statement, signed under penalty of perjury, attesting that the shareholder is a U.S. resident individual or corporation, and does not maintain a permanent establishment in Italy, and must set forth other required information. The normal time for processing requests for certification by the IRS is normally about six to eight weeks.

Where the Beneficial Owner has not provided the above mentioned documentation, the dividend paying agent will deduct from the gross amount of the dividend the substitute tax at the statutory rate of 26%. The U.S. recipient will then be entitled to claim from the Italian Tax Authorities the difference (treaty refund) between the domestic rate and the Treaty one by filing specific forms (certificate) with the Italian Tax Authorities.

As reflected in the Deposit Agreement, if any tax or other governmental charge shall become payable by or on behalf of the Custodian or the Depositary with respect to an ADR, any Deposited Securities represented by the American Depositary Shares (ADSs), such tax or other governmental charge shall be paid by the Holder hereof to the Depositary. The Depositary may refuse to effect any registration, registration of transfer, split-up or combination hereof or any withdrawal of such Deposited Securities until such payment is made. The Depositary may also deduct from any distributions on or in respect of Deposited Securities, or may sell by public or private sale for the account of the Holder hereof any part or all of such Deposited Securities (after attempting by reasonable means to notify the Holder hereof prior to such sale), and may apply such deduction or the proceeds of any such sale in payment of such tax or other governmental charge, the Holder hereof remaining liable for any deficiency, and shall reduce the number of ADSs to reflect any such sales of shares. Pursuant to the Deposit Agreement, the Depositary and the Custodian may make and maintain arrangements to enable persons that are considered United States residents for purposes of applicable law to receive any tax rebates (pursuant to an applicable Treaty or otherwise) or other tax related benefits relating to distributions on the ADSs to which such persons are entitled. Notwithstanding any other terms of the Deposit Agreement or the ADR, absent the gross negligence or bad faith of, respectively, the Depositary and the Company, the Depositary and the Company assume no obligation, and shall not be subject to any liability, for the failure of any Holder or Beneficial Owner, or its agent or agents, to receive any tax benefit under applicable law or Tax Treaties. The Depositary shall not be liable for any acts or omissions of any other party in connection with any attempts to obtain any such benefit, and Holders and Beneficial Owners hereby agree that each of them shall be conclusively bound by any deadline established by the Depositary in connection therewith.

Capital gains tax

This paragraph concerns and applies to capital gains out of the scope of a business activity carried out in Italy.

Profits gained by Italian resident individuals, not in connection with entrepreneurial activity, in financial year 2019, are subject to substitute tax for 26%.

For gains deriving from the sale of non-substantial interest, two different systems may be applied at the option of the shareholder as an alternative to the filing of the tax return:

- the so-called “administered savings” tax regime (risparmio amministrato), based on which intermediaries acting as shares depositaries shall apply a substitute tax (26%) on each gain, on a cash basis. If the sale of shares generated a loss, said loss may be carried forward up to the fourth following year; and

- the so-called “portfolio management” tax regime (risparmio gestito) which is applicable when the shares form part of a portfolio managed by an Italian asset management company. The accrued net profit of the portfolio is subject to a 26% substitute tax to be applied by the portfolio.

Gains realized by non-residents from non-substantial interest in listed companies are deemed not to be realized in Italy and consequently are not subject to the capital gains tax.

On the contrary, gains realized by non-residents from substantial interests even in listed companies are deemed to be realized in Italy and consequently are subject to the capital gains tax.

However, double taxation treaties may eliminate the capital gains tax. Under the income tax convention between the United States and Italy, a U.S. resident will not be subject to the capital gains tax unless the shares or ADRs form part of the business property of a permanent establishment of the holder in Italy or pertain to a fixed establishment available to a shareholder in Italy for the purposes of performing independent personal services. U.S. residents who sell shares may be required to produce appropriate documentation establishing that the above mentioned conditions of non taxability pursuant to the convention have been satisfied.

Financial Transactions Tax

Italian Law No. 228 of December 24, 2012 has introduced a Financial Transactions Tax which applies to the transfer of shares, ADR and other financial instruments issued by companies resident in Italy. The tax rate applicable is 0.10% for ADR negotiated in regulated markets (like the NYSE).

Non-Italian intermediaries, involved in the transactions of Eni ADR, must withhold and pay the Financial Transactions Tax. For this purpose, non-Italian intermediaries can appoint an Italian Tax Representative, according to the Italian tax law.

Inheritance and gift tax

Pursuant to Law Decree No. 262 of October 3, 2006, converted with amendments by Law No. 286 of November 24, 2006, effective from November 29, 2006, and Law No. 296 of December 27, 2006, the transfers of any valuable assets (including shares) as a result of death or donation (or other transfers for no consideration) and the creation of liens on such assets for a specific purpose are taxed as follows:

(a) 4 per cent: if the transfer is made to spouses and direct descendants or ancestors; in this case, the transfer is subject to tax on the value exceeding €1,000,000 (per beneficiary);

(b) 6 per cent: if the transfer if made to brothers and sisters; in this case, the transfer is subject to the tax on the value exceeding €100,000 (per beneficiary);

(c) 6 per cent: if the transfer is made to relatives up to the fourth degree, to persons related by direct affinity, as well as to persons related by collateral affinity up to the third degree; and

(d) 8 per cent: in all other cases.

If the transfer is made in favor of persons with severe disabilities, the tax applies on the value exceeding €1,500,000. Moreover, an anti-avoidance rule is provided for by Law No. 383 of October 18, 2001 for any gift of assets (including shares) which, if sold for consideration, would give rise to capital gains subject to a substitute tax (imposta sostitutiva) provided for by Decree No. 461 of November 21, 1997. In particular, if the donee sells the shares for consideration within five years from the receipt thereof as a gift, the donee is required to pay a relevant substitute tax on capital gains as if the gift had never taken place.

United States taxation

The following is a summary of certain U.S. federal income tax consequences to U.S. Holders (as defined below) of the ownership and disposition of Shares or ADSs. This summary is addressed to U.S. Holders that hold Shares or ADSs as capital assets, and does not purport to address all material tax consequences of the ownership of Shares or ADSs. The summary does not address special classes of investors, such as tax-exempt entities, dealers in securities, traders in securities that elect to mark-to-market, certain insurance companies, broker-dealers, investors liable for alternative minimum tax, investors that actually or constructively own 10% or more of the combined voting power of Eni SpA's voting stock or of the total value of Eni SpA's stock, a person that purchases or sells Shares or ADSs as part of a wash sale for U.S. federal income tax purposes, investors that hold Shares or ADSs as part of a straddle or a hedging or conversion transaction and investors whose "functional currency" is not the U.S. dollar.

This summary is based on the tax laws of the United States (including the Internal Revenue Code of 1986, as amended, (the "Code"), its legislative history, existing and proposed regulations thereunder, published rulings and court decisions) as in effect on the date hereof, and which are subject to change (or changes in interpretation), possibly with retroactive effect. The summary is based in part on representations of the Depositary and assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms. U.S. Holders should consult their own tax advisors to determine the U.S. federal, state and local and foreign tax consequences to them of the ownership and disposition of Shares or ADSs.

If a partnership holds the Shares or ADSs, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership. A partner in a partnership holding the Shares or ADSs should consult its tax advisor with regard to the U.S. federal income tax treatment of an investment in the Shares or ADSs.

As used in this section, the term "U.S. Holder" means a beneficial owner of Shares or ADSs that is: (i) a citizen or resident of the United States; (ii) a domestic corporation; (iii) an estate the income of which is subject to the U.S. federal income tax without regard to its source; or (iv) a trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust.

The discussion does not address any aspects of U.S. taxation other than U.S. federal income taxation. In particular, U.S. Holders are urged to confirm their eligibility for benefits under the income tax convention between the United States and Italy with their advisors and to discuss with their advisors any possible consequences of their failure to qualify for such benefits. In general, and taking into account the earlier assumptions, for U.S. federal income tax purposes, U.S. Holders who own ADRs evidencing ADSs will be treated as owners of the underlying Shares. Exchanges of Shares for ADRs and ADRs for Shares generally will not be subject to U.S. federal income tax.

Dividends

Subject to the passive foreign investment company (PFIC), rules discussed below, distributions paid on the shares will generally be treated as dividends for U.S. federal income tax purposes to the extent paid out of Eni SpA's current or accumulated earnings and profits as determined for U.S. federal income tax purposes, but will not be eligible for the dividends-received deduction generally allowed to U.S. corporations. To the extent that a distribution exceeds Eni SpA's earnings and profits, it will be treated, first, as a non-taxable return of capital to the extent of the U.S. Holder's tax basis in the Shares or ADSs, and thereafter as capital gain. A U.S. Holder will be subject to U.S. federal taxation, on the date of actual or constructive receipt by the U.S. Holder (in the case of Shares) or by the Depositary (in the case of ADSs) with respect to the gross amount of any dividends, including any Italian tax withheld therefrom, without regard to whether any portion of such tax may be refunded to the U.S. Holder by the Italian Tax Authorities. For non-corporate U.S. Holders, dividends paid that constitute qualified dividend income will be taxable at the preferential rates applicable to long-term capital gains provided that such person holds the Shares or ADSs for more than 60 days during the 121 day period beginning 60 days before the ex-dividend date and meet other holding period requirements. Dividends paid by the Group with respect to the Shares or ADSs will generally be qualified dividend income. The amount of the dividend distribution that must be included in the income of a U.S. Holder will be the U.S. dollar value of the euro payments made, determined at the spot EUR/USD rate on the date the dividend distribution is includible in such person's income, regardless of whether the payment is in fact converted into U.S. dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the U.S. Holder includes the dividend payment in income to the date he or she converts the payment into U.S. dollars will be treated as ordinary income or loss and will not be eligible for the special tax rate applicable to qualified dividend income. The gain or loss generally will be income or loss from sources within the United States for foreign tax credit limitation purposes.

Subject to certain conditions and limitations, Italian tax withheld from dividends will be treated as a foreign income tax eligible for credit against the U.S. Holder's U.S. federal income tax liability. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are subject to the preferential rates. To the extent a refund of the tax withheld is available to a U.S. Holder under Italian law or under the income tax convention between the United States and Italy, the amount of tax withheld that is refundable will not be eligible for credit against his or her U.S. federal income tax liability. See "Italian taxation – Income tax" above, for the procedures for obtaining a tax refund. For foreign tax credit purposes, dividends paid on the shares will be income from sources outside the United States and will, generally be "passive" income for purposes of computing the foreign tax credit allowable to you.

Sale or exchange of shares

Subject to the PFIC rules discussed below, a U.S. Holder generally will recognize gain or loss for U.S. federal income tax purposes on the sale or exchange of Shares or ADSs equal to the difference between the U.S. Holder's adjusted basis in the Shares or ADSs (determined in U.S. dollars), as the case may be, and the amount realized on the sale or exchange (or if the amount realized is denominated in a foreign currency its U.S. dollar equivalent, determined at the spot rate on the date of disposition). Generally, such gain or loss will be treated as capital gain or loss if the Shares or ADSs are held as capital assets and will be a long-term capital gain or loss if the Shares or ADSs have been held for more than one year on the date of such sale or exchange. Long-term capital gain of a non corporate U.S. Holder is generally taxed at preferential rates. In addition, any such gain or loss realized by a U.S. Holder generally will be treated as U.S. source income or loss for U.S. foreign tax credit purposes.

PFIC rules

Eni believes that Shares and ADSs should not be treated as stock of a PFIC for U.S. federal income tax purposes, but this conclusion is a factual determination that is made annually and thus may be subject to change. If Eni SpA were to be treated as a PFIC, gain realized on the sale or other disposition of your

Shares or ADSs would in general not be treated as capital gain. Instead, unless a U.S. Holder elects to be taxed annually on a mark-to-market basis with respect to the Shares or ADSs, the U.S. Holder would be treated as having realized such gains and certain "excess distributions" ratably over the holding period for the Shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain or distribution was allocated, together with an interest charge in respect of the tax attributable to each such year. With certain exceptions, a U.S. Holder's Shares or ADSs will be treated as stock in a PFIC if Eni SpA were a PFIC at any time during the period the Shares or ADSs were held. Dividends received from Eni SpA will not be eligible for the preferential tax rates applicable to qualified dividend income if Eni SpA is treated as a PFIC with respect to the U.S. Holders either in the taxable year of the distribution or the preceding taxable year, but instead will be taxable at rates applicable to ordinary income.

Documents on display

Eni's Annual Report and Accounts and any other document concerning the Company are also available online on the Company website at: http://www.eni.com/en_IT/documentation/documentation.page?type=bil-rap.

The Company is subject to the information requirements of the U.S. Security Exchange Act of 1934 applicable to foreign private issuers.

In accordance with these requirements, Eni files its Annual Report on Form 20-F and other related documents with the U.S. SEC. It's possible to read and copy documents that have been filed with the U.S. via commercial document retrieval services, and from the SEC website (www.sec.gov).

Item 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the possibility that the exposure to fluctuations in commodity prices, currency exchange rates, interest rates or other market benchmarks will adversely affect the value of the Group's financial assets, liabilities or expected future cash flows. Eni's financial performance is particularly sensitive to changes in the price of crude oil and movements in the EUR/USD exchange rate. Overall, a rise in the price of crude oil has a positive effect on Eni's results from operations and liquidity due to increased revenues from oil&gas production. Conversely, a decline in crude oil prices reduces Eni's results from operations and liquidity.

The impact of changes in crude oil prices on the Company's refining and marketing and petrochemical businesses depends upon the speed at which the prices of finished products adjust to reflect changes in crude oil prices. In addition, the Group's activities are, to various degrees, sensitive to fluctuations in the EUR/USD exchange rate as commodities are generally priced internationally in U.S. dollars or linked to dollar denominated products. Overall, an appreciation of the euro against the dollar reduces the Group's results from operations and liquidity, and vice versa.

As part of its financing and cash management activities, the Company uses derivative instruments to manage its exposure to changes in interest rates and foreign exchange rates. These instruments are principally interest rate and currency swaps. The Company also enters into commodity derivatives as part of its ordinary commercial, optimization and risk management activities, as well as exceptionally to hedge the exposure to variability in future cash flows due to movements in commodity prices, in view of pursuing acquisitions of oil&gas reserves as part of the Company's ordinary asset portfolio management or other strategic initiatives.

The Company actively manages market risk in accordance with a set of policies and guidelines that provide a centralized model of undertaking finance, treasury and risk management operations based on the Company's departments of operational finance: the parent company's (Eni SpA) finance department and its subsidiaries Eni Finance International, Eni Finance USA and Banque Eni, which is subject to certain bank regulatory restrictions preventing the Group's exposure to concentrations of credit risk, and Eni Trading & Shipping, that is in charge to execute certain activities relating to commodity derivatives. In particular, Eni SpA and Eni Finance International manage the Group subsidiaries' financing requirements in and outside Italy, respectively, covering funding requirements and using available surpluses. All transactions concerning currencies and derivative contracts on interest rates and currencies are managed by the parent company. The commodity risk of each business unit (Eni's business lines or subsidiaries) is pooled and managed by the parent company Midstream business department, with Eni Trading & Shipping executing the negotiation of commodity derivatives.

During 2013, the above mentioned centralized model for the execution of financial derivatives has been ring fenced in light of the relevant new financial regulations which became effective (EMIR/Dodd Frank act). Eni's activities are in compliance with regulatory requirements for execution of financial derivatives on European and non-European Regulated Markets, on Multilateral Trading Facilities, on Organized Trading Facilities or bilaterally with OTC counterparties.

In addition to the reinforcement of the centralized execution model, as required by the new financial regulation, in 2013 the EMIR concepts of "risk reducing" and "non-risk reducing" derivatives were introduced. Company's activities in financial derivatives were thus classified in order to clearly: a) isolate ex ante non-risk reducing activities; b) define a priori the types of OTC derivative contracts included in the hedging portfolios and the eligibility criteria, and stating that the transactions in contracts included in the hedging portfolios are limited to covering risks directly related to commercial or treasury financing activities; and c) provide for a sufficiently disaggregate view of the hedging portfolios in terms of for example asset class, product and time horizon, in order to establish the direct link between the portfolio of hedging transactions and the risks that this portfolio seeks to hedge. A derivative can be qualified a risk reducing instrument when, by itself or in combination with other derivative contracts (so-called macro or portfolio hedging) it:

(i) directly or through closely correlated instruments (so-called proxy hedging) covers the risks arising from potential changes in the value of different assets under Eni control or that Eni will have under its controls in the normal course of business driven by fluctuation of interest rates, inflation rates, foreign exchange rates or credit risk; or

(ii) qualifies as a hedging contract pursuant to IFRS.

Use of financial derivatives (in euro or currencies different from euro) is allowed with the following risk reducing purposes:

- *Back to back:* includes market risk-free instruments that are negotiated in accordance to an execution criteria and normally settled with an intermediation fee. They normally comply with hedge accounting requirements or own use exemption. These are transaction-based activities characterized by a substantial absence of market risk. A hedging instrument can be considered back to back when the financial derivative is structured as to match as much as possible asset class, size and maturity of the hedged position. As a result, the combination of the hedged item, normally a single asset/contract or an order received by mean of an internal derivative, and the hedging instrument, i.e. the financial derivative, is substantially market risk free or is exposed only to a basic risk related to the ineffective portion of the hedging item. In addition, the hedging item may entail counterparty risk and operational risk. These derivatives are normally accounted for as hedges for financial statement purposes.
- *Flow hedging*: flow hedging seeks to optimize Group hedging requirements by pooling different positions retained by the business units and then by entering derivative instruments to hedge net exposures, in accordance to a portfolio basis. A central department processes a continuous flow of orders from the Group various business units and then acts as a single broker on financial markets. Flow hedging is characterized by the lack of direct control by the central broker entity on the received orders, which are normally related to assets managed by the business units. The central broker entity can normally rely on a continuous flow of hedging orders that can be predictable to a large extent, on the basis of the regular hedging programs made by the Group's business units. The central entity is therefore in the position to net opposite orders, by retaining the level of risk necessary to cover timing, volume and asset class mismatch among orders. The benefits are the maximization of integration across the whole of the Group assets portfolio and the related netting potential, avoiding unnecessary derivatives, thus reducing costs and aggregated notional amounts of hedging programs. Flow hedging is managed on a portfolio basis and is dynamic by nature, since resulting net position is normally adjusted in order to take into account new orders received and maximum allowed exposure, related to timing, volume and asset classes mismatch. Those derivatives are accounted to profit and loss as the hedging of net exposures does not qualify as hedges under IFRS.
- *Asset-backed hedging:* is a portfolio-based activity performed to protect assets extrinsic value which is the fair value that a third party would potentially pay to buy the flexibility associated to assets available to the Group. It is normally characterized by a maximum level of market risk related to the size of managed assets and the volatility of underlying commodities. The more flexible the asset, the higher its extrinsic value that can be normally quantified as an option premium, linked to the price of an underlying commodity, volatility, time, interest rate. To protect the value of asset flexibility, a business unit may transfer to a central entity part or the whole of an asset flexibility or a portfolio of flexibilities and the central entity will hedge such flexibility on financial markets so to lock its value by monetizing it via derivatives. Hedging strategies adopted for asset-backed hedging are normally portfolio based, very dynamic and entail large use of proxies. Depending on the optimization model such strategies are continuously adjusting relevant hedging ratios buying and selling same financial products several times, since the underlying asset flexibility to be hedged is changing depending on price level, price volatility, time to delivery, etc. These derivatives may lead to gains as well as losses which in each case may be significant and are accounted through profit and loss as they lack the hedge requirements provided by IFRS. However, we believe that the risks associated with those derivatives are mitigated by the natural hedge granted by the asset availability.
- *Portfolio management:* is a portfolio based activity performed on a combination of underlying positions, such as physical assets (production plants, transmission infrastructures, storages, etc.), commercial assets (spot and forward short/medium/long term supply and sale contracts with physical delivery) and related financial derivatives. Normally, the target of a portfolio management activity is to optimize managed assets' base by running quantitative models which, given production/consumption forecasts, prices scenarios and logistic flexibility/constraints, determine the optimal configuration in terms of volume, price and flexibility for physical and commercial assets in the portfolio. Financial derivatives are then used in the portfolio management activity in order to manage the overall risk level associated to such optimal

configuration within a set tolerance or to balance the combined risk-reward profile of the portfolio in line with company's targets. Market risk associated to portfolio management is proportional to assets size and maturity and volatility/correlation of underlying markets. Financial derivatives are normally used to hedge the resulting net position, but they might hedge also single physical/commercial assets included in the portfolio. The activity is dynamic by nature, since optimization models are run periodically, even on a daily and infra-daily timescale, in order to rebalance optimal configuration in view of actual or forecast changes in volumes, prices and flexibility. As a consequence, financial derivatives are also managed dynamically, with a continuous adjustment that might lead to buy and sell the same financial product several times in a given time frame. These derivatives may lead to gains, as well as losses which in each case may be significant and are accounted through profit as they lack the hedge requirements provided by IFRS.

Pursuant to internal policy, all derivatives transactions concerning interest rates and foreign currencies are executed for risk reducing purposes, as described above. Only commodity derivatives can also be executed in the context of non-risk reducing operations and be consequently classified as Proprietary Trading, which is an ancillary activity not related to industrial assets that makes use of financial derivatives which are entered into with the objective to obtain an uncertain profit, if favorable market expectations occur.

Eni monitors on a daily basis that every activity involving derivatives is correctly classified according to the risk reducing taxonomy (i.e. back to back, flow hedging, asset-backed hedging or portfolio management), is directly or indirectly related to the hedged industrial assets and effectively optimizes the risk profile to which Eni is, or could be, exposed. When some derivatives fail to prove their risk reducing purpose, they are reclassified as Proprietary Trading. Provided that Proprietary Trading is segregated ex ante from other activities, its resulting market risk exposure is subject to specific limits expressed in terms of Stop Loss, VaR and notional amounts. The aggregated notional amounts of non-risk reducing derivatives at Group level are constantly benchmarked with the thresholds required by relevant international financial regulations.

Please refer to "Item 18 – Note 27 of the Notes on Consolidated Financial Statements" for a qualitative and quantitative discussion of the Company's exposure to market risks.

Item 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Item 12A. Debt securities

Not applicable.

Item 12B. Warrants and rights

Not applicable.

Item 12C. Other securities

Not applicable.

Item 12D. American Depositary Shares

In the United States, Eni's securities are traded in the form of American Depositary Shares (ADSs) which are listed on the NYSE. ADSs are evidenced by American Depositary Receipts (ADRs), and each ADR represents two Eni ordinary shares.

Pursuant to the Deposit Agreement dated June 27, 2017 (the "Deposit Agreement") between Eni, Citibank N.A. and the holders and beneficial owners ADSs, Citibank N.A. serves as the Depositary for Eni's ADR Program, and Citibank N.A. Milan Branch serves as Custodian.

Computershare is the transfer agent for the Eni SpA ADR program.

Fees and charges payable by ADR holders

Pursuant to the Deposit Agreement, ADR holders may be required to pay various fees to the Depositary, and the Depositary may refuse to provide any service for which a fee is assessed until the applicable fee has been paid.

The following ADS fees are payable under the terms of the Deposit Agreement:

Service	Rate	By Whom Paid
(1) Issuance of ADSs (e.g., an issuance upon a deposit of Shares, upon a change in the ADS(s)-to-Share(s) ratio, or for any other reason), excluding issuances as a result of distributions described in paragraph (4) below.	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) issued.	Person receiving ADSs.
(2) Cancellation of ADSs (e.g., a cancellation of ADSs for delivery of deposited Shares, upon a change in the ADS(s)-to-Share(s) ratio, or for any other reason).	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) cancelled.	Person whose ADSs are being cancelled.
(3) Distribution of cash dividends or other cash distributions (e.g., upon a sale of rights and other entitlements).	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) held.	Person to whom the distribution is made.
(4) Distribution of ADSs pursuant to (i) stock dividends or other free stock distributions, or (ii) an exercise of rights to purchase additional ADSs.	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) held.	Person to whom the distribution is made.
(5) Distribution of securities other than ADSs or rights to purchase additional ADSs (e.g., spin-off shares).	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) held.	Person to whom the distribution is made.
(6) ADS Services.	Up to U.S. $5.00 per 100 ADSs (or fraction thereof) held on the applicable record date(s) established by the Depositary.	Person holding ADSs on the applicable record date(s) established by the Depositary.

Direct and indirect payments by the Depositary

The Depositary has agreed to reimburse certain company expenses related to the ADR Program and incurred in connection with the program and the listing of Eni's ADSs on the NYSE. These expenses are mainly related to legal and accounting fees incurred in connection with the preparation of regulatory filings and other documentation related to ongoing U.S. SEC compliance, NYSE listing fees, listing and custodian bank fees, advertising, certain investor relationship programs or special investor relations activities.

For the year 2018, the Depositary will reimburse to Eni up to $1,800,000 in connection with the above mentioned expenditures.

The Depositary has also agreed to waive certain standard fees associated with the administration of the ADR Program.

PART II

Item 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

Item 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

None.

Item 15. CONTROLS AND PROCEDURES

Disclosure controls and procedures

In designing and evaluating the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act"), the Company's management, including the Chief Executive Officer and the Chief Financial Officer, recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and the Company's management necessarily was required to apply its judgment in evaluating the cost benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected.

It should be noted that the Company has investments in certain non-consolidated entities. As the Company does not control or manage these entities, its disclosure controls and procedures with respect to such entities are necessarily more limited than those it maintains with respect to its consolidated subsidiaries.

The Company's management, with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Rule 13a-14(c) under the Exchange Act as of the end of the period covered by this Annual Report on Form 20-F. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Exchange Act Rules 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, the effectiveness of an internal control system may change over time.

The Internal Control Committee assists the Board of Directors in setting out the main principles for the internal control system so as to appropriately identify and adequately evaluate, manage, and monitor the main risks related to the Company and its subsidiaries, by laying down the compatibility criteria between said risks and sound corporate management. In addition, this Committee assesses, at least annually, the adequacy, effectiveness, and actual operations of the internal control system.

The Company's management, including the Chief Executive Officer and the Chief Financial Officer, conducted an evaluation of the effectiveness of its internal control over financial reporting based on the Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the

Treadway Commission (CoSO) in 2013. Based on the results of this evaluation, the Group's management concluded that its internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, has been audited by E&Y SpA, an independent registered public accounting firm, as stated in its report that is included on page F-2 of this Annual Report on Form 20-F.

Changes in Internal Control over Financial Reporting

There have not been changes in the Company's Internal Control over Financial Reporting that occurred during the period covered by this Form 20-F that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 16. [RESERVED]

Item 16A. Board of Statutory Auditors financial expert

Eni's Board of Statutory Auditors has determined that the five members of Eni's Board of Statutory Auditors are "audit committee financial expert": Rosalba Casiraghi, who is the Chairman of the Board, Enrico Maria Bignami, Paola Camagni, Andrea Parolini and Marco Seracini. All members are independent.

Item 16B. Code of Ethics

Eni adopted a Code of Ethics that applies to all Eni's employees, including Chiefs, Officers, principal Financial and Accounting Officers, Directors and Statutory Auditors. Eni published its Code of Ethics on Eni's website. It is accessible at www.eni.com, under the section Governance. A copy of this Code of Ethics is included as an exhibit to this Annual Report on Form 20-F.

Eni's Code of Ethics contains ethical guidelines, describes corporate values and requires standards of business conduct and moral integrity. The ethical guidelines are designed to deter wrongdoing and to promote honest and ethical conduct, compliance with applicable laws and regulations and internal reporting of violations of the guidelines. The code affirms the principles of accounting transparency and internal control and endorses human rights and the issue of the sustainability of the business model.

Item 16C. Principal accountant fees and services

EY SpA has served as Eni principal independent public auditor for fiscal years 2018 and 2017 for which audited Consolidated Financial Statements appear in this Annual Report on Form 20-F.

The following table shows total fees paid by Eni, its consolidated and non-consolidated subsidiaries and Eni's share of fees incurred by joint ventures for services provided by Eni to its public auditors EY SpA and its respective member firms, for the years ended December 31, 2018 and 2017, respectively:

	Year ended December 31,	
	2018	2017
	(€ thousand)	
Audit fees	25,445	23,193
Audit-related fees	1,628	1,712
Tax fees		
All other fees		12
Total	**27,073**	**24,917**

Audit fees include professional services rendered by the principal accountant for the audit of the registrant's annual financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements, including the audit on the Company's internal control over financial reporting.

Audit-related fees include assurance and related services by the principal accountant that are reasonably related to the performance of the audit or review of the registrant's financial statements and are not reported as Audit fees in this Item. The fees disclosed in this category mainly include audits of pension and benefit plans, merger and acquisition due diligence, audit and consultancy services rendered in connection with acquisition deals, certification services not provided for by law and regulations and consultations concerning financial accounting and reporting standards.

Tax fees include professional services rendered by the principal accountant for tax compliance, tax advice, and tax planning. The fees disclosed in this category mainly include fees billed for the assistance with compliance and reporting of income and value-added taxes, assistance with assessment of new or changing tax regimes, tax consultancy in connection with merger and acquisition deals, services rendered in connection with tax refunds, assistance rendered on occasion of tax inspections and in connection with tax claims and recourses and assistance with assessing relevant rules, regulations and facts going into Eni correspondence with tax authorities.

All other fees include products and services provided by the principal accountant, other than the services reported in Audit fees, Audit-related fees and Tax fees of this Item and consists primarily of fees billed for consultancy services related to IT and secretarial services that are permissible under applicable rules and regulations.

Pre-approval policies and procedures of the Internal Control Committee

The Board of Statutory Auditors has adopted a pre-approval policy for audit and non-audit services that set forth the procedures and the conditions pursuant to which services proposed to be performed by the principal auditors may be pre-approved. Such policy is applied to entities within the Eni Group which are either controlled or jointly controlled (directly or indirectly) by Eni SpA. According to this policy, permissible services within the other audit services category are pre-approved by the Board of Statutory Auditors. The Board of Statutory Auditors approval is required on a case-by-case basis for those requests regarding: (i) audit-related services; and (ii) non-audit services to be performed by the external auditors which are permissible under applicable rules and regulations. In such cases, the Company's Internal Audit Department is charged with performing an initial assessment of each request to be submitted to the Board of Statutory Auditors for approval. The Internal Audit Department periodically reports to Eni's Board of Statutory Auditors on the status of both pre-approved services and services approved on a case-by-case basis rendered by the external auditors.

During 2018, no audit-related fees, tax fees or other non-audit fees were approved by the Board of Statutory Auditors pursuant to the de minimis exception to the pre-approval requirement provided by paragraph (c)(7)(i) (C) of Rule 2-01 of Regulation S-X.

Item 16D. Exemptions from the Listing Standards for Audit Committees

Making use of the exemption provided by Rule 10A-3(c)(3) for non-U.S. private issuers, Eni has identified the Board of Statutory Auditors as the body that, starting from June 1, 2005, performs the functions required by the U.S. SEC rules and the Sarbanes-Oxley Act to be carried out by the audit committees of non-U.S. companies listed on the NYSE (see "Item 6 – Board of Statutory Auditors" above).

Item 16E. Purchases of equity securities by the issuer and affiliated purchasers

The issuer and its affiliated purchasers have not executed any purchase of equity securities of the issuer since the end of 2014 and up to and as of the date of the filing of our annual report on Form 20-F for the year ended December 31, 2018.

Item 16F. Change in Registrant's Certifying Accountant

Not applicable.

Item 16G. Significant differences in Corporate Governance practices as per Section 303A.11 of the New York Stock Exchange Listed Company Manual

Corporate Governance. Eni's Governance structure follows the traditional model as defined by the Italian Civil Code which provides for two main separate corporate bodies, the Board of Directors and the Board of Statutory Auditors to whom management and monitoring duties are respectively entrusted. This model differs from the U.S. one-tier model in which the Board of Directors is the sole corporate body responsible for management, with an Audit Committee established within the Board performing monitoring activities. The following offers a description of the most significant differences between corporate governance practices adopted by U.S. domestic companies under the NYSE standards and those followed by Eni, including with reference to Corporate Governance Code for Italian listed companies, which Eni has adopted (hereinafter the Corporate Governance Code).

Independent Directors

NYSE standards. In accordance with NYSE standards, the majority of the members on the Boards of Directors of U.S. companies must be independent. A Director qualifies as independent when the Board affirmatively determines that such Director does not have a material relationship with the listed company (and its subsidiaries), either directly, or indirectly. In particular, a Director may not be deemed independent if he or she or an immediate family member has a certain specific relationship with the issuer, its auditors or companies that have material business relationships with the issuer (e.g. he or she is an employee of the issuer or a partner of the Auditor). In addition, a Director cannot be considered independent in the three-year "cooling-off" period following the termination of any relationship that compromised a Director's independence.

Eni standards. In Italy, the Consolidated Law on Financial Intermediation states that at least one of the Directors or two, if the Board is composed of more than seven members, must meet the independence requirements for Statutory Auditors of listed companies. In particular, a Director may not be deemed independent if he/she or an immediate family member has a relationship with the issuer, with its Directors or with the companies in the same group of the issuer that could influence the independence of judgement.

Eni's By-laws require that at least one Director – if the Board has no more than five members – or at least three Directors – if the Board is composed of more than five members – must satisfy the independence requirements. The Corporate Governance Code provides for additional independence requirements, recommending that the Board of Directors includes an adequate number of independent non-executive Directors. In particular, for issuers belonging to FTSE-MIB index of the Italian Stock Market, like Eni, the Corporate Governance Code recommends that at least one-third of the members of the Board of Directors shall be independent Directors. In any event, independent Directors shall not be fewer than two. Independence is defined as not being currently or recently involved in any direct or indirect relationship with the issuer or other parties associated with the issuer and that may influence his/her independent judgment. After the appointment of a Director who qualifies as independent and subsequently, upon the occurrence of circumstances affecting the independence requirements and in any case at least once a year, the Board of Directors assesses the independence of the Director. The Board of Statutory Auditors verifies the correct application of the criteria and procedures adopted by the Board of Directors to evaluate the independence of its members. The Board of Directors shall disclose the result of its evaluations, after the appointment, through a press release to the market and, subsequently, in the Annual Corporate Governance Report. In accordance with Eni's By-laws, if a Director, who qualifies as independent, does not or no longer satisfies the independence requirements established by law, the Board declares the Director disqualified and provides for their substitution. Directors shall notify the Company if they should no longer satisfy the independence and integrity requirements or if cause for ineligibility or incompatibility should arise.

Meetings of non-executive Directors

NYSE standards. Non-executive Directors, including those who are not independent, must meet on a regular basis without the executive Directors. In addition, if the group of non-executive Directors includes Directors who are not independent, independent Directors should meet separately at least once a year.

Eni standards. Pursuant to Corporate Governance Code, independent Directors shall meet at least once a year without the other Directors. During 2018, Eni's independent Directors had opportunities to meet, informally, to hold discussions and exchange opinions.

Audit Committee

NYSE standards. Listed U.S. companies must have an Audit Committee that satisfies the requirements of Rule 10A-3 under the Securities Exchange Act of 1934 and that complies with the provisions of the Sarbanes-Oxley Act and of Section 303A.07 of the NYSE Listed Company Manual.

Eni standards. At its Meeting of March 22, 2005, the Board of Directors, as permitted by the rules of the U.S. Securities and Exchange Commission applicable to foreign issuers listed on regulated U.S. markets, assigned to the Board of Statutory Auditors, effective from June 1, 2005 and within the limits set by Italian law, the functions specified and the responsibilities assigned to the Audit Committee of such foreign issuers by the Sarbanes-Oxley Act and the U.S. SEC rules (see "Item 6 – Board of Statutory Auditors" earlier). Under Section 303A.07 of the NYSE Listed Company Manual, audit committees of U.S. companies have additional functions and duties which are not mandatory for non-U.S. private issuers and which are therefore not included in the list of functions reported in "Item 6 – Board of Statutory Auditors".

Nominating/Corporate Governance Committee

NYSE standards. U.S. listed companies must have a Nominating/Corporate Governance Committee (or equivalent body) composed entirely of independent Directors whose functions include, but are not limited to, selecting qualified candidates for the office of Director for submission to the Shareholders' Meeting, as well as developing and recommending corporate governance guidelines to the Board of Directors. This provision is not binding for non-U.S. private issuers.

Eni standards. Pursuant to the Corporate Governance Code, the Board of Directors shall establish among its members a nomination committee the majority of whose members shall be independent Directors. The Nomination Committee of Eni is made up of three to four Directors, a majority of whom shall be independent in accordance with the recommendations of the Corporate Governance Code[1]. On

(1) The Committee is currently made up of four Directors, three of whom are independent.

April 13, 2017, the Board of Directors of Eni established the Nomination Committee, chaired by Diva Moriani (independent Director) and composed of Andrea Gemma (independent Director), Fabrizio Pagani (non-executive Director) and Domenico Livio Trombone (independent Director). Further details on this Committee are reported in the Item 6.

Remuneration Committee

NYSE standards. U.S. listed companies must have a Remuneration Committee composed entirely of independent Directors who must satisfy the independence requirements provided for its members. The Remuneration Committee must have a written charter that addresses the Committee's purpose and responsibilities within the limit set forth by the listing rules. The Remuneration Committee may, in its sole discretion, retain or obtain the advice of a compensation consultant, independent legal counsel or other adviser and shall be directly responsible for the appointment, compensation and oversight of the work of any compensation consultant, independent legal counsel or other adviser retained by it. These provisions are not binding for non-U.S. private issuers.

Eni standards. Pursuant to the Corporate Governance Code, the Board of Directors shall establish among its members a Remuneration Committee made up of three to four non-executive Directors, all of whom shall be independent or, alternatively, a majority of whom shall be independent. In the latter case, the Chairman of the Committee shall be chosen from among the independent Directors. At least one of the Committee's members shall have an adequate understanding of and experience in financial matters or compensation policies. First established by the Board of Directors in 1996, the Remuneration Committee is currently chaired by Director Andrea Gemma. The other members include directors Pietro Guindani, Alessandro Lorenzi and Diva Moriani. The composition and functions of the Remuneration Committee are outlined in the committee charter ("Rules") available on the Company's website (https://www.eni.com/docs/en_IT/enicom/company/governance/rules-of-the-remuneration-committee.pdf). Further details on this Committee are reported in the Item 6.

Code of Business Conduct and Ethics

NYSE standards. The NYSE listing standards require each U.S. listed company to adopt a Code of Business Conduct and Ethics for its Directors, Officers and employees, and to promptly disclose any waivers of the code for Directors or Executive Officers.

Eni standards. At its Meetings of December 15, 2003 and January 28, 2004, the Board of Directors of Eni approved an organizational, management and control model pursuant to Italian Legislative Decree No. 231 of 2001 (hereinafter "Model 231") and established the associated Eni Watch Structure. Moreover, after subsequent approvals of the updates to Model 231 in response to changes in the Italian legislation governing the matter and in the Company organizational structures, on March 14, 2008, the Board of Directors approved the overall revision of Model 231 and adopted Eni's Code of Ethics – replacing the previous version of Eni's Code of Conduct of 1998. Most recently, the Board of Directors, in its meeting held on November 23, 2017, approved the updating of Model 231 and Eni's Code of Ethics, as defined by the CEO with the support of the "Technical Committee 231", consisting of members from the Company's Legal Affairs, Integrated Compliance Department, Human Resources and Organization and Internal Audit units. Eni's Code of Ethics, which is an integral part of Model 231, sets out a clear definition of the value system that Eni recognizes, accepts and upholds and the responsibilities that Eni assumes internally and externally in order to ensure that all its business activities are conducted in compliance with the law, in a context of fair competition, with honesty, integrity, correctness and in good faith, respecting the legitimate interests of all the stakeholders with whom Eni interacts on an ongoing basis. These include shareholders, employees, suppliers, customers, commercial and financial partners, and the local communities and institutions of the countries where Eni operates. All Eni personnel, without exception or distinction, starting with Directors, senior management and members of the Company's bodies, as also required under U.S. SEC rules and the Sarbanes-Oxley Act, are committed to observing and enforcing the principles set out in the Code of Ethics in the performance of their functions and duties. The synergies between the Code of Ethics and Model 231 are underscored by the designation of the Eni Watch Structure, established under Model 231, as the Guarantor of the Code of Ethics. The Guarantor of the Code of Ethics acts to ensure the protection and promotion of the above principles. Every six months, it presents a report on the implementation of the Code to the Control and Risk Committee, to the Board of Statutory Auditors and to the Chairman and the CEO, who in turn reports on this to the Board of Directors. At present, the Watch

Structure of Eni SpA is composed of three external members, including the Chairman, and four internal members. The internal members are Company executives in charge of Legal Affairs, labor law matters and disputes, Internal Audit and Integrated Compliance. External members are independent professionals, experts in law and/or economic matters. Also in order to grant the Watch Structure the greatest extent of autonomy and independence, the set of rules adopted by the Watch Structure provide for specific quorum to convene and to pass resolutions so to ensure that all resolutions are effectively adopted with the favourable vote of the majority of the external members.

Item 16H. Mine safety disclosure

Not applicable since Eni does not engage in mining operations.

PART III

Item 17. FINANCIAL STATEMENTS

Not applicable.

Item 18. FINANCIAL STATEMENTS

Index to Financial Statements:

Item 19. EXHIBITS

1. By-laws of Eni SpA

8. List of subsidiaries

11. Code of Ethics

Certifications:

12.1. Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act
12.2. Certification pursuant to Rule 13a-14(a) of the Securities Exchange Act

13.1. Certification furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act (such certificate is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporated by reference with any filing under the Securities Act)

13.2. Certification furnished pursuant to Rule 13a-14(b) of the Securities Exchange Act (such certificate is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporated by reference with any filing under the Securities Act)

15.a(i) Excerpt of the pages and sections of the remuneration report prepared in accordance to Italian listing standards for the year 2018 incorporated herein by reference
15.a(ii) Report of DeGolyer and MacNaughton
15.a(iii) Report of Ryder Scott Co
15.a(iv) Report of SGS Nederland B. V.
101.a(i) XBRL Document

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Eni S.p.A.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Eni S.p.A. (the Company) as of December 31, 2018 and 2017, the related consolidated profit and loss accounts and consolidated statements of comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated April 5, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young S.p.A.

We have served as the Company's auditor since 2010.

Rome, Italy

April 5, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Eni S.p.A.

Opinion on Internal Control over Financial Reporting

We have audited Eni S.p.A.'s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Eni S.p.A. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated profit and loss accounts and consolidated statements of comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated April 5, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young S.p.A.

Rome, Italy

April 5, 2019

CONSOLIDATED BALANCE SHEET
(euro million)

		December 31, 2018		December 31, 2017	
	Note	Total amount	*of which with related parties*	Total amount	*of which with related parties*
ASSETS					
Current assets					
Cash and cash equivalents	(5)	10,836		7,363	
Financial assets held for trading	(6)	6,552		6,012	
Financial assets available for sale				207	
Other current financial assets	(15)	300	*49*	316	*73*
Trade and other receivables	(7)	14,101	*633*	15,421	*834*
Inventories	(8)	4,651		4,621	
Income tax receivables	(9)	191		191	
Other tax receivables	(9)	561		729	
Other current assets	(10) (23)	2,258	*71*	1,573	*30*
		39,450		**36,433**	
Non-current assets					
Property, plant and equipment	(11)	60,302		63,158	
Inventories – compulsory stock	(8)	1,217		1,283	
Intangible assets	(12)	3,170		2,925	
Equity-accounted investments	(14)	7,044		3,511	
Other investments	(14)	919		219	
Other non-current financial assets	(15)	1,253	*915*	1,675	*1,214*
Deferred tax assets	(22)	3,931		4,078	
Other non-current assets	(10) (23)	792	*160*	1,323	*46*
		78,628		**78,172**	
Assets held for sale	(24)	**295**		**323**	
TOTAL ASSETS		**118,373**		**114,928**	
LIABILITIES AND SHAREHOLDERS' EQUITY					
Current liabilities					
Short-term debt	(18)	2,182	*661*	2,242	*164*
Current portion of long-term debt	(18)	3,601		2,286	
Trade and other payables	(16)	16,747	*3,664*	16,748	*2,808*
Income tax payables	(9)	440		472	
Other tax payables	(9)	1,432		1,472	
Other current liabilities	(17) (23)	3,980	*63*	1,515	*60*
		28,382		**24,735**	
Non-current liabilities					
Long-term debt	(18)	20,082		20,179	
Provisions for contingencies	(20)	11,886		13,447	
Provisions for employee benefits	(21)	1,117		1,022	
Deferred tax liabilities	(22)	4,272		5,900	
Other non-current liabilities	(17) (23)	1,502	*23*	1,479	*23*
		38,859		**42,027**	
Liabilities directly associated with assets held for sale	(24)	**59**		**87**	
TOTAL LIABILITIES		**67,300**		**66,849**	
SHAREHOLDERS' EQUITY	(25)				
Non-controlling interest		**57**		**49**	
Eni shareholders' equity					
Share capital		4,005		4,005	
Retained earnings		36,702		35,966	
Cumulative currency translation differences		6,605		4,818	
Other reserves		1,672		1,889	
Treasury shares		(581)		(581)	
Interim dividend		(1,513)		(1,441)	
Net profit (loss)		4,126		3,374	
Total Eni shareholders' equity		**51,016**		**48,030**	
TOTAL SHAREHOLDERS' EQUITY		**51,073**		**48,079**	
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY		**118,373**		**114,928**	

CONSOLIDATED PROFIT AND LOSS ACCOUNT
(euro million except as otherwise stated)

	Note	2018		2017		2016	
		Total amount	*of which with related parties*	**Total amount**	*of which with related parties*	**Total amount**	*of which with related parties*
REVENUES	(28)						
Net sales from operations		75,822	*1,383*	66,919	*1,567*	55,762	*1,238*
Other income and revenues		1,116	*8*	4,058	*41*	931	*74*
		76,938		**70,977**		**56,693**	
COSTS							
Purchases, services and other	(29)	(55,622)	*(8,009)*	(51,548)	*(9,164)*	(43,278)	*(8,212)*
Net (impairment losses) reversals of trade and other receivables	(7)	(415)	*26*	(913)		(846)	
Payroll and related costs	(29)	(3,093)	*(22)*	(2,951)	*(34)*	(2,994)	*(24)*
Other operating income (expense)	(23)	129	*319*	(32)	*331*	16	*247*
Depreciation and amortization	(11)(12)	(6,988)		(7,483)		(7,559)	
Net (impairment losses) reversals of tangible and intangible assets	(13)	(866)		225		475	
Write-off of tangible and intangible assets	(11)(12)	(100)		(263)		(350)	
OPERATING PROFIT (LOSS)		**9,983**		**8,012**		**2,157**	
FINANCE INCOME (EXPENSE)							
Finance income	(30)	3,967	*115*	3,924	*191*	5,850	*157*
Finance expense	(30)	(4,663)	*(283)*	(5,886)	*(4)*	(6,232)	*(145)*
Net finance income (expense) from financial assets held for trading	(30)	32		(111)		(21)	
Derivative financial instruments	(23)	(307)		837		(482)	*27*
		(971)		**(1,236)**		**(885)**	
INCOME (EXPENSE) FROM INVESTMENTS	(14)(31)						
Share of profit (loss) from equity-accounted investments		(68)		(267)		(326)	
Other gain (loss) from investments		1,163		335		(54)	
		1,095		**68**		**(380)**	
PROFIT (LOSS) BEFORE INCOME TAXES		**10,107**		**6,844**		**892**	
Income taxes	(32)	(5,970)		(3,467)		(1,936)	
Net profit (loss) for the year - continuing operations		**4,137**		**3,377**		**(1,044)**	
Net profit (loss) for the year - discontinued operations						**(413)**	
Net profit (loss) for the year		**4,137**		**3,377**		**(1,457)**	
Attributable to Eni:							
- continuing operations		4,126		3,374		(1,051)	
- discontinued operations						(413)	
		4,126		**3,374**		**(1,464)**	
Attributable to non-controlling interest:							
- continuing operations		11		3		7	
- discontinued operations							
		11		**3**		**7**	
Earnings per share attributable to Eni (€ per share)	(33)						
Basic		1.15		0.94		(0.41)	
Diluted		1.15		0.94		(0.41)	
Earnings per share attributable to Eni – Continuing operations (€ per share)	(33)						
Basic		1.15		0.94		(0.29)	
Diluted		1.15		0.94		(0.29)	

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)
(euro million)

	Note	2018	2017	2016
Net profit (loss)		**4,137**	**3,377**	**(1,457)**
Other items of comprehensive income (loss)				
Items that are not reclassified to profit or loss in later periods				
Remeasurements of defined benefit plans	(25)	(15)	(33)	16
Change in the fair value of minor investments with effects to OCI	(25)	15		
Tax effect related to other comprehensive income not to be reclassified to profit or loss in subsequent periods	(25)	(2)	29	(35)
		(2)	**(4)**	**(19)**
Items that may be reclassified to profit or loss in later periods				
Currency translation differences		1,787	(5,573)	1,198
Change in the fair value of available-for-sale financial instruments	(25)		(5)	(4)
Change in the fair value of cash flow hedging derivatives	(25)	(243)	(6)	883
Share of other comprehensive income on equity-accounted entities	(25)	(24)	69	32
Tax effect related to other comprehensive income to be reclassified to profit or loss in subsequent periods	(25)	58	1	(220)
		1,578	**(5,514)**	**1,889**
Total other items of comprehensive income (loss)		**1,576**	**(5,518)**	**1,870**
Total comprehensive income (loss)		**5,713**	**(2,141)**	**413**
Attributable to Eni				
- continuing operations		5,702	(2,144)	819
- discontinued operations				(413)
		5,702	**(2,144)**	**406**
Attributable to non-controlling interest				
- continuing operations		11	3	7
- discontinued operations				
		11	**3**	**7**

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(euro million)

		Eni shareholders' equity									
	Note	Share capital	Retained earnings	Cumulative currency translation differences	Other reserves	Treasury shares	Interim dividend	Net profit (loss) for the year	Total	Non-controlling interest	Total shareholders' equity
Balance at December 31, 2017	(25)	**4,005**	**35,966**	**4,818**	**1,889**	**(581)**	**(1,441)**	**3,374**	**48,030**	**49**	**48,079**
Changes in accounting policies (IFRS 9 and 15)	(3)		245						**245**		**245**
Balance at January 1, 2018		**4,005**	**36,211**	**4,818**	**1,889**	**(581)**	**(1,441)**	**3,374**	**48,275**	**49**	**48,324**
Net profit for the year								**4,126**	**4,126**	**11**	**4,137**
Other items of comprehensive income (loss)											
Items that are not reclassified to profit or loss in later periods											
Remeasurements of defined benefit plans net of tax effect	(25)				(17)				(17)		(17)
Change of minor investments measured at fair value with effects recognised in OCI	(25)				15				15		15
					(2)				**(2)**		**(2)**
Items that may be reclassified to profit or loss in later periods											
Currency translation differences	(25)			1,787					1,787		1,787
Change in the fair value of cash flow hedge derivatives net of tax effect	(25)				(185)				(185)		(185)
Share of "Other comprehensive income" on equity-accounted entities	(25)				(24)				(24)		(24)
				1,787	**(209)**				**1,578**		**1,578**
Total comprehensive income (loss) of the year				**1,787**	**(211)**			**4,126**	**5,702**	**11**	**5,713**
Transactions with shareholders											
Dividend distribution of Eni SpA (€0.40 per share in settlement of 2017 interim dividend of €0.40 per share)	(25)						1,441	(2,881)	(1,440)		(1,440)
Interim dividend distribution of Eni SpA (€0.42 per share)	(25)						(1,513)		(1,513)		(1,513)
Dividend distribution of other companies										(3)	(3)
Allocation of 2017 net income			493					(493)			
			493				**(72)**	**(3,374)**	**(2,953)**	**(3)**	**(2,956)**
Other changes in shareholders' equity											
Long-term share-based incentive plan			5						5		5
Other changes			(7)		(6)				(13)		(13)
			(2)		**(6)**				**(8)**		**(8)**
Balance at December 31, 2018	(25)	**4,005**	**36,702**	**6,605**	**1,672**	**(581)**	**(1,513)**	**4,126**	**51,016**	**57**	**51,073**

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (continued)
(euro million)

		Eni shareholders' equity									
	Note	Share capital	Retained earnings	Cumulative currency translation differences	Other reserves	Treasury shares	Interim dividend	Net profit (loss) for the year	Total	Non-controlling interest	Total shareholders' equity
Balance at December 31, 2016	(25)	**4,005**	**40,367**	**10,319**	**1,832**	**(581)**	**(1,441)**	**(1,464)**	**53,037**	**49**	**53,086**
Net profit for the year								**3,374**	**3,374**	**3**	**3,377**
Other items of comprehensive income (loss)											
Items that are not reclassified to profit or loss in later periods											
Remeasurements of defined benefit plans net of tax effect	(25)				(4)				(4)		(4)
					(4)				**(4)**		**(4)**
Items that may be reclassified to profit or loss in later periods											
Currency translation differences	(25)			(5,575)	2				(5,573)		(5,573)
Change in the fair value of other available-for-sale financial instruments net of tax effect	(25)				(4)				(4)		(4)
Change in the fair value of cash flow hedge derivatives net of tax effect	(25)				(6)				(6)		(6)
Share of "Other comprehensive income" on equity-accounted entities	(25)				69				69		69
				(5,575)	**61**				**(5,514)**		**(5,514)**
Total comprehensive income (loss) of the year				**(5,575)**	**57**			**3,374**	**(2,144)**	**3**	**(2,141)**
Transactions with shareholders											
Dividend distribution of Eni SpA (€0.40 per share in settlement of 2016 interim dividend of €0.40 per share)	(25)						1,441	(2,881)	(1,440)		(1,440)
Interim dividend distribution of Eni SpA (€0.40 per share)	(25)						(1,441)		(1,441)		(1,441)
Dividend distribution of other companies										(3)	(3)
Allocation of 2016 net loss			(4,345)					4,345			
			(4,345)					**1,464**	**(2,881)**	**(3)**	**(2,884)**
Other changes in shareholders' equity											
Other changes			(56)	74					18		18
			(56)	**74**					**18**		**18**
Balance at December 31, 2017	(25)	**4,005**	**35,966**	**4,818**	**1,889**	**(581)**	**(1,441)**	**3,374**	**48,030**	**49**	**48,079**

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (continued)
(euro million)

	Eni shareholders' equity									
	Share capital	Retained earnings	Cumulative currency translation differences	Other reserves	Treasury shares	Interim dividend	Net profit for the year	Total	Non-controlling interest	Total shareholders' equity
Balance at December 31, 2015	**4,005**	**51,985**	**9,129**	**1,173**	**(581)**	**(1,440)**	**(8,778)**	**55,493**	**1,916**	**57,409**
Net profit (loss) for the year							**(1,464)**	**(1,464)**	**7**	**(1,457)**
Other items of comprehensive income (loss)										
Items that are not reclassified to profit or (loss) in later periods										
Remeasurements of defined benefit plans net of tax effect				(19)				(19)		(19)
				(19)				**(19)**		**(19)**
Items that may be reclassified to profit or (loss) in later periods										
Currency translation differences			1,190	8				1,198		1,198
Change in the fair value of other available-for-sale financial instruments net of tax effect				(4)				(4)		(4)
Change in the fair value of cash flow hedge derivatives net of tax effect				663				663		663
Share of "Other comprehensive income" on equity-accounted entities				32				32		32
			1,190	**699**				**1,889**		**1,889**
Total comprehensive income (loss) of the year			**1,190**	**680**			**(1,464)**	**406**	**7**	**413**
Transactions with shareholders										
Dividend distribution of Eni SpA (€0.40 per share in settlement of 2015 interim dividend of €0.40 per share)........		(1,028)				1,440	(1,852)	(1,440)		(1,440)
Interim dividend distribution of Eni SpA (€0.40 per share)						(1,441)		(1,441)		(1,441)
Dividend distribution of other companies									(4)	(4)
Allocation of 2015 net loss		(10,630)					10,630			
		(11,658)				**(1)**	**8,778**	**(2,881)**	**(4)**	**(2,885)**
Other changes in shareholders' equity										
Exclusion from the scope of consolidation of Saipem group following the sale of the control									(1,872)	(1,872)
Reclassification to profit and loss account of amounts previously recognized in other comprehensive income related to Saipem..		(8)		(20)				(28)		(28)
Other changes		48		(1)				47	2	49
		40		**(21)**				**19**	**(1,870)**	**(1,851)**
Balance at December 31, 2016	**4,005**	**40,367**	**10,319**	**1,832**	**(581)**	**(1,441)**	**(1,464)**	**53,037**	**49**	**53,086**

CONSOLIDATED STATEMENT OF CASH FLOWS
(euro million)

	Note	2018	2017	2016
Net profit (loss) of the year – continuing operations		4,137	3,377	(1,044)
Adjustments to reconcile net profit (loss) to net cash provided by operating activities				
Depreciation and amortization	(11) (12)	6,988	7,483	7,559
Net Impairments (reversals) of tangible and intangible assets	(13)	866	(225)	(475)
Write-off of tangible and intangible assets	(11) (12)	100	263	350
Share of (profit) loss of equity-accounted investments	(14) (31)	68	267	326
Gain on disposal of assets, net		(474)	(3,446)	(48)
Dividend income	(31)	(231)	(205)	(143)
Interest income		(185)	(283)	(209)
Interest expense		614	671	645
Income taxes	(32)	5,970	3,467	1,936
Other changes		(474)	894	(9)
Changes in working capital:				
- inventories		*15*	*(346)*	*(273)*
- trade receivables		*334*	*657*	*1,286*
- trade payables		*642*	*284*	*1,495*
- provisions for contingencies		*(238)*	*96*	*(1,043)*
- other assets and liabilities		*879*	*749*	*647*
Cash flow from changes in working capital		1,632	1,440	2,112
Net change in the provisions for employee benefits		109	38	22
Dividends received		275	291	212
Interest received		87	104	160
Interest paid		(609)	(582)	(780)
Income taxes paid, net of tax receivables received		(5,226)	(3,437)	(2,941)
Net cash provided by operating activities		**13,647**	**10,117**	**7,673**
- of which with related parties	(36)	***(2,707)***	***(2,843)***	***(3,749)***
Investing activities:				
- tangible assets	(11)	*(8,778)*	*(8,490)*	*(9,067)*
- intangible assets	(12)	*(341)*	*(191)*	*(113)*
- consolidated subsidiaries and businesses net of cash and cash equivalent acquired	(26)	*(119)*		
- investments	(14)	*(125)*	*(510)*	*(1,164)*
- securities		*(432)*	*(316)*	*(1,336)*
- financial receivables		*(554)*	*(657)*	*(1,208)*
- change in payables in relation to investing activities and capitalized depreciation		*408*	*152*	*(8)*
Cash flow from investing activities		(9,941)	(10,012)	(12,896)
Disposals:				
- tangible assets		*1,089*	*2,745*	*19*
- intangible assets		*5*	*2*	
- consolidated subsidiaries and businesses net of cash and cash equivalent disposed of	(26)	*(47)*	*2,662*	*(362)*
- tax on disposals			*(436)*	
- investments		*195*	*482*	*508*
- securities		*61*	*224*	*20*
- financial receivables		*496*	*999*	*8,063*
- change in receivables in relation to disposals		*606*	*(434)*	*205*
Cash flow from disposals		2,405	6,244	8,453
Net cash used in investing activities		**(7,536)**	**(3,768)**	**(4,443)**
- of which with related parties	(36)	***(3,314)***	***(3,115)***	***3,752***

CONSOLIDATED STATEMENT OF CASH FLOWS (continued)

(euro million)

	Note	2018	2017	2016
Increase in long-term financial debt	(18)	3,790	1,842	4,202
Repayments of long-term financial debt	(18)	(2,757)	(2,973)	(2,323)
Increase (decrease) in short-term financial debt	(18)	(713)	(581)	(2,645)
		320	**(1,712)**	**(766)**
Dividends paid to Eni's shareholders		(2,954)	(2,880)	(2,881)
Dividends paid to non-controlling interest		(3)	(3)	(4)
Net cash used in financing activities		**(2,637)**	**(4,595)**	**(3,651)**
- of which with related parties	*(36)*	***16***	***(16)***	***(192)***
Effect of change in consolidation (inclusion/exclusion of significant/insignificant subsidiaries)			7	(5)
Effect of cash and cash equivalents pertaining to discontinued operations				889
Effect of exchange rate changes and other changes on cash and cash equivalents		18	(72)	2
Net cash flow of the year		**3,492**	**1,689**	**465**
Cash and cash equivalents – beginning of the year	(5)	**7,363**	**5,674**	**5,209**
Cash and cash equivalents – end of the year[(a)]	(5)	**10,855**	**7,363**	**5,674**

(a) Cash and cash equivalents as of December 31, 2018, include €19 million of cash and cash equivalents of consolidated subsidiaries held for sale that were reported in the item Assets held for sale in the balance sheet

Notes on Consolidated Financial Statements

1 Significant accounting policies, estimates and judgements

Basis of preparation

The Consolidated Financial Statements of the Eni Group have been prepared in accordance with International Financial Reporting Standards (IFRS)[1] as issued by the International Accounting Standards Board (IASB). Oil and natural gas exploration and production activity is accounted for in accordance with internationally accepted accounting standards taking into account the applicable IFRS requirements.

The Consolidated Financial Statements have been prepared under the historical cost convention, taking into account, where appropriate, value adjustments, except for certain items that under IFRSs must be measured at fair value as described in the accounting policies that follow.

The 2018 Consolidated Financial Statements included in the Annual Report on Form 20-F, approved by the Eni's Board of Directors on April 4, 2019, were audited by the external auditor Ernst & Young SpA. The external auditor of Eni SpA, as the main external auditor, is wholly in charge of the auditing activities of the Consolidated Financial Statements; when there are other external auditors, Ernst & Young SpA takes the responsibility of their work.

The Consolidated Financial Statements are presented in euro and all values are rounded to the nearest million euros (€ million), except where otherwise indicated.

Significant accounting estimates and judgements

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses recognised in the financial statements, as well as amounts included in the notes thereto, including disclosure of contingent assets and contingent liabilities. Estimates made are based on complex judgements and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgements and estimates to be used in the preparation of the Consolidated Financial Statements are in relation to the accounting for oil and natural gas activities, specifically in the determination of proved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, decommissioning and restoration liabilities, business combinations, employee benefits and recognition of environmental liabilities. Although the Company uses its best estimates and judgements, actual results could differ from the estimates and assumptions used. The accounting estimates and judgements relevant for the preparation of the Consolidated Financial Statement are described below.

Principles of consolidation

Subsidiaries

The Consolidated Financial Statements comprise the financial statements of the parent Company Eni SpA and those of its subsidiaries, being those entities over which the Company has control, either directly or indirectly, through exposure or rights to their variable returns and the ability to affect those returns through its power over the investees. To have power over an investee, the investor must have existing rights that give it the current ability to direct the relevant activities of the investee, i.e. the activities that significantly affect the investee's returns.

(1) IFRSs include also International Accounting Standards (IAS), currently effective, as well as the interpretations developed by the IFRS Interpretations Committee, previously named International Financial Reporting Interpretations Committee (IFRIC) and initially Standing Interpretations Committee (SIC).

Subsidiaries are consolidated, on the basis of consistent accounting policies, from the date on which control is obtained until the date that control ceases. Assets, liabilities, income and expenses of consolidated subsidiaries are fully recognised with those of the parent in the Consolidated Financial Statements; the parent's investment in each subsidiary is eliminated against the corresponding parent's portion of equity of each subsidiary. Non-controlling interests are presented separately in the balance sheet within equity; the profit or loss attributable to non-controlling interests is presented in a specific line item of the profit and loss account.

For entities acting as sole-operator in the management of oil&gas contracts on behalf of companies participating in a joint project, the activities are financed proportionally based on a budget approved by the participating companies upon presentation of periodical reports of proceeds and expenses. Costs and revenue and other operating data (production, reserves, etc.) of the project, as well as the related obligations arising from the project, are recognised directly in the financial statements of the companies involved based on their own share. Some subsidiaries are not consolidated because they are not significant, either individually or in the aggregate; this exclusion has not produced significant[2] effects on the Consolidated Financial Statements[3].

When the proportion of the equity held by non-controlling interests changes, any difference between the consideration paid/received and the amount by which the non-controlling interests are adjusted is attributed to Eni shareholders' equity. Conversely, the sale of equity interests with loss of control determines the recognition in the profit and loss account of: (i) any gain or loss calculated as the difference between the consideration received and the corresponding transferred net assets; (ii) any gain or loss recognised as a result of the re-measurement of any investment retained in the former subsidiary at its fair value; and (iii) any amount related to the former subsidiary previously recognised in other comprehensive income which may be reclassified subsequently to the profit and loss account[4]. Any investment retained in the former subsidiary is recognised at its fair value at the date when control is lost and shall be accounted for in accordance with the applicable measurement criteria.

Interests in joint arrangements

Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. Investments in joint ventures are accounted for using the equity method as described in the accounting policy for "The equity method of accounting".

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have enforceable rights to the assets, and enforceable obligations for the liabilities, relating to the arrangement. In the Consolidated Financial Statements, Eni recognises its share of the assets/liabilities and revenue/expenses of joint operations on the basis of its rights and obligations relating to the arrangements.

After the initial recognition, the assets/liabilities and revenue/expenses of the joint operations are measured in accordance with the applicable measurement criteria. Not significant joint operations are accounted for using the equity method or, if this does not result in a misrepresentation of the Company's financial position and performance, at cost net of any impairment losses.

Investments in associates

An associate is an entity over which Eni has significant influence, that is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control of those policies. Investments in associates are accounted for using the equity method as described in the accounting policy for "The equity method of accounting".

(2) According to the requirements of the Conceptual Framework for Financial Reporting, "information is material if omitting it or misstating it could influence decisions that users make on the basis of financial information about a specific reporting entity".
(3) Unconsolidated subsidiaries are accounted for as described in the accounting policy for "The equity method of accounting".
(4) Conversely, any amount related to the former subsidiary previously recognised in other comprehensive income, which may not be reclassified subsequently to the profit and loss account, are reclassified in another item of equity.

Consolidated companies' financial statements are audited by external auditors who audit also the information required for the preparation of the Consolidated Financial Statements.

The equity method of accounting

Investments in joint ventures, associates and not significant unconsolidated subsidiaries, are accounted for using the equity method.[5] [6]

Under the equity method, investments are initially recognised at cost, allocating, similarly to business combinations procedures, the purchase price of the investment to the investee's assets/liabilities; if this allocation is provisionally recognised at initial recognition, it can be retrospectively adjusted within one year from the date of initial recognition, to reflect new information obtained about facts and circumstances that existed at the date of initial recognition. Subsequently, the carrying amount is adjusted to reflect: (i) the investor's share of the profit or loss of the investee after the date of acquisition; and (ii) the investor's share of the investee's other comprehensive income. Distributions received from an equity-accounted investee reduce the carrying amount of the investment. In applying the equity method, consolidation adjustments are considered (see also the accounting policy for "Subsidiaries"). When there is objective evidence of impairment (e.g. relevant breaches of contracts, significant financial difficulty, probable default of the counterparty, etc.), the recoverability is tested by comparing the carrying amount and the related recoverable amount determined by adopting the criteria indicated in the accounting policy for "Property, plant and equipment". When an impairment loss no longer exists or has decreased, a reversal of the impairment loss is recognised in the profit and loss account within "Other gain (loss) from investments". The impairment reversal shall not exceed the previously recognised impairment losses. Losses arising from the application of the equity method in excess of the carrying amount of the investment, recognised in the profit and loss account within "Income (Expense) from investments", reduce the carrying amount of any financing receivables towards the investee for which settlement is neither planned nor likely to occur in the foreseeable future and which are, in substance, an extension of the investment in the investee (the so-called long-term interests).

The sale of equity interests with loss of joint control or significant influence over the investee determines the recognition in the profit and loss account of: (i) any gain or loss calculated as the difference between the consideration received and the corresponding transferred share; (ii) any gain or loss recognised as a result of the re-measurement of any investment retained in the former joint venture/associate at its fair value[7]; and (iii) any amount related to the former joint venture/associate previously recognised in other comprehensive income which may be reclassified subsequently to the profit and loss account[8]. Any investment retained in the former joint venture/associate is recognised at its fair value at the date when joint control or significant influence is lost and shall be accounted for in accordance with the applicable measurement criteria.

The investor's share of losses of an investee, that exceeds the carrying amount of the investment and any long-term interests, is recognised in a specific provision only to the extent that the investor has incurred legal or constructive obligations or made payments on behalf of the investee.

Business combinations

Business combinations are accounted for by applying the acquisition method. The consideration transferred in a business combination is the sum of the acquisition-date fair value of the assets transferred, the liabilities incurred and the equity interests issued by the acquirer. Acquisition-related costs are accounted for as expenses when incurred.

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(5) In the case of step acquisition of significant influence (joint control), the investment is recognised, at the acquisition date of significant influence (joint control), at the amount deriving from the use of the equity method assuming the adoption of this method since initial acquisition; the "step-up" of the carrying amount of interests owned before the acquisition of significant influence (joint control) is taken to equity.

(6) Joint ventures, associates and not significant unconsolidated subsidiaries are accounted for at cost less any accumulated impairment losses, if this does not result in a misrepresentation of the Company's financial position and performance.

(7) If the retained investment continues to be accounted for using the equity method, no re-measurement at fair value is recognised in the profit and loss account.

(8) Conversely, any amount related to the former joint venture/associate previously recognised in other comprehensive income, which may not be reclassified subsequently to the profit and loss account, are reclassified in another item of equity.

The acquirer shall measure the identifiable assets acquired and liabilities assumed at their acquisition-date fair values[9], unless another measurement basis is required by IFRSs. The excess of the consideration transferred over the Group's share of the net of the acquisition-date amounts of the identifiable assets acquired and liabilities assumed is recognised, in the balance sheet, as goodwill; conversely, a gain on a bargain purchase is recognised in the profit and loss account.

Any non-controlling interests are measured as the proportionate share in the recognised amounts of the acquiree's identifiable net assets at the acquisition date excluding, hence, the portion of goodwill attributable to them (partial goodwill method); as an alternative, non-controlling interests may be measured at fair value, which means that goodwill includes the portion attributable to them (full goodwill method)[10]. The choice of measurement basis for goodwill (partial goodwill method vs. full goodwill method) is made on a transaction-by-transaction basis.

In a business combination achieved in stages, the purchase price is determined by summing the acquisition-date fair value of previously held equity interests in the acquiree and the consideration transferred for obtaining control; the previously held equity interests are re-measured at their acquisition-date fair value and the resulting gain or loss, if any, is recognised in the profit and loss account. Furthermore, on obtaining control, any amount recognised in other comprehensive income related to the previously held equity interests is reclassified to the profit and loss account, or in another item of equity when such amount may not be reclassified to the profit and loss account.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the provisional amounts recognised at the acquisition date shall be retrospectively adjusted within one year from the acquisition date, to reflect new information obtained about facts and circumstances that existed as of the acquisition date.

The acquisition of interests in a joint operation whose activity constitutes a business is accounted for applying the principles on business combinations accounting.

Significant accounting estimates and judgements: investments and business combinations

The assessment of the existence of control, joint control, significant influence over an investee, as well as for joint operations, the assessment of the existence of enforceable rights and obligations imply that the management makes complex judgements on the basis of the characteristics of the investee's structure, arrangements between parties and other relevant facts and circumstances. Significant accounting estimates by management are required also for measuring the identifiable assets acquired and the liabilities assumed, in a business combination, at their acquisition-date fair values. For such measurement, to be performed also for the application of the equity method, Eni adopts the valuation techniques generally used by market participants taking into account the available information; for the most significant business combinations, Eni engages external independent evaluators.

Intragroup transactions

All balances and transactions between consolidated companies, and not yet realised with third parties, including unrealised profits arising from such transactions have been eliminated.

Unrealised profits arising from transactions between the Group and its equity-accounted entities are eliminated to the extent of the Group's interest in the equity-accounted entity. In both cases, unrealised losses are not eliminated unless the transaction provides evidence of an impairment loss of the asset transferred.

Foreign currency translation

The financial statements of foreign operations having a functional currency other than the euro, that represents the parent's functional currency, are translated into euro using the spot exchange rates on the balance sheet date for assets and liabilities, historical exchange rates for equity and average exchange rates for the profit and loss account and the statement of cash flows (source: Reuters — WMR).

(9) Fair value measurement principles are described below in the accounting policy for "Fair value measurements".

(10) The choice between partial goodwill and full goodwill method is made also for business combinations resulting in the recognition of a gain on bargain purchase in the profit and loss account.

The cumulative resulting exchange differences are presented in the separate component of Eni shareholders' equity "Cumulative currency translation differences"[11]. Cumulative amount of exchange differences relating to a foreign operation are reclassified to the profit and loss account when the entity disposes the entire interest in that foreign operation or when the partial disposal involves the loss of control, joint control or significant influence over the foreign operation. On a partial disposal that does not involve loss of control of a subsidiary that includes a foreign operation, the proportionate share of the cumulative exchange differences is reattributed to the non-controlling interests in that foreign operation. On a partial disposal that does not involve loss of joint control or significant influence, the proportionate share of the cumulative exchange differences is reclassified to the profit and loss account. The repayment of share capital made by a subsidiary having a functional currency other than the euro, without a change in the ownership interest, implies that the proportionate share of the cumulative amount of exchange differences relating to the subsidiary is reclassified to the profit and loss account.

The financial statements of foreign operations which are translated into euro are denominated in the foreign operations' functional currencies which generally is the U.S. dollar.

The main foreign exchange rates used to translate the financial statements into the parent's functional currency are indicated below:

(currency amount for €1)	**Annual average exchange rate 2018**	**Exchange rate at December 31, 2018**	**Annual average exchange rate 2017**	**Exchange rate at December 31, 2017**	**Annual average exchange rate 2016**	**Exchange rate at December 31, 2016**
U.S. Dollar	1.18	1.15	1.13	1.20	1.11	1.05
Pound Sterling	0.88	0.89	0.88	0.88	0.82	0.86
Norwegian Krone	9.60	9.94	9.33	9.83	9.29	9.09
Australian Dollar	1.58	1.62	1.47	1.53	1.49	1.46

Significant accounting policies

The most significant accounting policies used in the preparation of the Consolidated Financial Statements are described below.

Oil and natural gas exploration, appraisal, development and production expenditure

Acquisition of exploration rights

Costs incurred for the acquisition of exploration rights (or their extension) are initially capitalised within the line item "Intangible assets" as "exploration rights — unproved" pending determination of whether the exploration and appraisal activities in the reference areas are successful or not. Unproved exploration rights are not amortised, but reviewed to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review is based on the confirmation of the commitment of the Company to continue the exploration activities and on the analysis of facts and circumstances that can show the existence of uncertainties related to the recoverability of the carrying amount. If no future activity is planned, the carrying amount of the related exploration rights is recognised in the profit and loss account as write-off. Lower value exploration rights are pooled and amortised on a straight-line basis over the estimated period of exploration. In the event of a discovery of proved reserves (i.e. upon recognition of proved reserves and internal approval for development), the carrying amount of the related unproved exploration rights is reclassified to "proved exploration rights", within the line item "Intangible assets". Upon reclassification, as well as whether there is any indication of impairment, the carrying amount of exploration rights to reclassify as proved is tested for impairment considering the higher of their value in use and their fair value less costs of disposal. From the commencement of production, proved exploration rights are amortised according to the unit of production method (the so-called UOP method, described in the accounting policy for "UOP depreciation, depletion and amortisation").

(11) When the foreign subsidiary is partially owned, the cumulative exchange differences, that are attributable to the non-controlling interests, are allocated to and recognised as part of "Non-controlling interest".

Acquisition of mineral interests

Costs incurred for the acquisition of mineral interests are capitalised in connection with the assets acquired (such as exploration potential, possible and probable reserves and proved reserves). When the acquisition is related to a set of exploration potential and reserves, the cost is allocated to the different assets acquired based on their expected discounted cash flows.

Acquired exploration potential is measured in accordance with the criteria illustrated in the accounting policy for "Acquisition of exploration rights". Costs associated with proved reserves are amortised according to the UOP method (see the accounting policy for "UOP depreciation, depletion and amortisation"). Expenditure associated with possible and probable reserves (unproved mineral interests) is not amortised until classified as proved reserves; in case of a negative result, it is written-off.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are recognised as an expense as incurred.

Costs directly associated with an exploration well are initially recognised within tangible assets in progress, as "exploration and appraisal costs — unproved" (exploration wells in progress) until the drilling of the well is completed and can continue to be capitalised in the following 12-month period pending the evaluation of drilling results (suspended exploration wells). If, at the end of this period, it is ascertained that the result is negative (no hydrocarbon found) or that the discovery is not sufficiently significant to justify the development, the wells are declared dry/unsuccessful and the related costs are written-off. Conversely, these costs continue to be capitalised if and until: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well, and (ii) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project; on the contrary, the capitalised costs are recognised in the profit and loss account as write-off. Analogous recognition criteria are adopted for the costs related to the appraisal activity. When proved reserves of oil and/or natural gas are determined, the relevant expenditure recognised as unproved is reclassified to proved exploration and appraisal costs, within tangible assets in progress. Upon reclassification, as well as whether there is any indication of impairment, the carrying amount of the costs to reclassify as proved is tested for impairment considering the higher of their value in use and their fair value less costs of disposal. From the commencement of production, proved exploration and appraisal costs are depreciated according to the UOP method (see the accounting policy for "UOP depreciation, depletion and amortisation").

Development expenditure

Development expenditure, including the costs related to unsuccessful and damaged development wells, are capitalised as "Tangible asset in progress — proved". Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil&gas. They are amortised, from the commencement of production, generally on a UOP basis. When development projects are unfeasible/not carried on, the related costs are written-off when it is decided to abandon the project. Development costs are tested for impairment in accordance with the criteria described in the accounting policy for "Property, plant and equipment".

UOP depreciation, depletion and amortisation

Proved oil&gas assets are depreciated generally under the UOP method, as their useful life is closely related to the availability of oil&gas reserves, by applying, to the depreciable amounts at the end of each quarter a rate representing the ratio between the volumes extracted during the quarter and the reserves existing at the end of the quarter, increased by the volumes extracted during the quarter. This method is applied with reference to the smallest aggregate representing a direct correlation between expenditures to be depreciated and oil&gas reserves. Proved exploration rights and acquired proved mineral interests are amortised over proved reserves; proved exploration and appraisal costs and development expenditure are depreciated over proved developed reserves.

Production costs

Production costs are those costs incurred to operate and maintain wells and field equipment and are recognised as an expense as incurred.

Production Sharing Agreements and buy-back contracts

Oil and gas reserves related to Production Sharing Agreements and buy-back contracts are determined on the basis of contractual terms related to the recovery of the contractor's costs to undertake and finance exploration, development and production activities at its own risk (Cost Oil) and the Company's stipulated share of the production remaining after such cost recovery (Profit Oil). Revenues from the sale of the lifted production, against both Cost Oil and Profit Oil, are accounted for on an accrual basis, whilst exploration, development and production costs are accounted for according to the above-mentioned accounting policies. The Company's share of production volumes and reserves includes the share of hydrocarbons that corresponds to the taxes to be paid, according to the contractual agreement, by the national government on behalf of the Company. As a consequence, the Company has to recognise at the same time an increase in the taxable profit, through the increase of the revenue, and a tax expense.

Decommissioning and restoration liabilities

Costs expected to be incurred with respect to the plugging and abandonment of a well, dismantlement and removal of production facilities, as well as site restoration, are capitalised, consistently with the accounting policy described under "Property, plant and equipment", and then depreciated on a UOP basis.

Significant accounting estimates and judgements: oil and natural gas activities

Engineering estimates of the Company's oil&gas reserves are inherently uncertain. Proved reserves are the estimated volumes of crude oil, natural gas and gas condensates, liquids and associated substances which geological and engineering data demonstrate that can be economically producible with reasonable certainty from known reservoirs under existing economic conditions and operating methods. Although there are authoritative guidelines regarding the engineering and geological criteria that must be met before estimated oil&gas reserves can be categorised as "proved", the accuracy of any reserve estimate depends on the quality of available data, the engineering and geological interpretation of such data and management's judgement.

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is made within a year after well completion. The evaluation process of a discovery, which requires performing additional appraisal activities on the potential oil and natural gas field and establishing the optimum development plans, can take longer, in most cases, depending on the complexity of the project and on the size of capital expenditures required. During this period, the costs related to these exploration wells remain suspended on the balance sheet. In any case, all such carried costs are reviewed, at least, on an annual basis to confirm the continued intent to develop, or otherwise to extract value from the discovery.

Field reserves will be categorised as proved only when all the criteria for attribution of proved status have been met. Initially, all booked reserves are classified as proved undeveloped. Subsequently, volumes are reclassified from proved undeveloped to proved developed as a consequence of development activity. Generally, reserves are booked as proved developed when the first oil or gas is produced. Major development projects typically take one to four years from the time of initial booking to the start of production. Eni reassesses its estimate of proved reserves periodically. The estimated proved reserves of oil and natural gas may be subject to future revision. Upward or downward revision may be made to the initial booking of reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity. In particular, changes in oil and natural gas prices could impact the amount of Eni's proved reserves in regards to the initial estimate and, in the case of production sharing agreements and buy-back contracts, the share of production and reserves to which Eni is entitled. Accordingly, the estimated reserves could be materially different from the quantities of oil and natural gas that ultimately will be recovered. Oil and natural gas reserves have a direct impact on certain amounts reported in the Consolidated Financial Statements. Estimated proved reserves are used in determining depreciation, amortisation and depletion charges and impairment charges. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depreciation, amortisation and depletion charge using the UOP method. Conversely, a decrease in estimated proved developed reserves increases depreciation, amortisation and depletion charge. Estimated proved reserves are affected, inter alia, by the trend of reference oil and gas commodity prices and by the specific legal agreement for the oil&gas activity.

In addition, estimated proved reserves are used to calculate future cash flows from oil&gas properties, which are used to assess any impairment loss.

Property, plant and equipment

Property, plant and equipment, including investment properties, are recognised using the cost model and stated at their purchase price or construction cost including any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. For assets that necessarily take a substantial period of time to get ready for their intended use, the purchase price or construction cost comprises the borrowing costs incurred in the period to get the asset ready for use that would have been avoided if the expenditure had not been made.

In the case of a present obligation for dismantling and removal of assets and restoration of sites, the initial carrying amount of an item of property, plant and equipment includes the estimated (discounted) costs to be incurred when the removal event occurs (a corresponding amount is recognised as part of a specific provision). Changes resulting from revisions to the timing or the amount of the original estimate of the provision are accounted for as described in the accounting policy for "Provisions, contingent liabilities and contingent assets"[12].

Property, plant and equipment are not revalued for financial reporting purposes.

Assets held under finance lease, or under arrangements that do not take the legal form of a finance lease but substantially transfer all the risks and rewards incidental to ownership of the leased asset, are recognised, at the commencement of the lease term, at their fair value, net of grants attributable to the lessee or, if lower, at the present value of the minimum lease payments. Leased assets are included within property, plant and equipment. A corresponding financing payable to the lessor is recognised.

Expenditures on upgrading, revamping and reconversion are recognised as items of property, plant and equipment when it is probable that they will increase the expected future economic benefits of the asset. Assets acquired for safety or environmental reasons, although not directly increasing the future economic benefits of any particular existing item of property, plant and equipment, qualify for recognition as assets when they are necessary for running the business.

Depreciation of tangible assets begins when they are available for use, i.e. when they are in the location and condition necessary for it to be capable of operating as planned. Property, plant and equipment are depreciated on a systematic basis, using a straight-line method over their useful life. The useful life is the period over which an asset is expected to be available for use by the Company. When tangible assets are composed of more than one significant part with different useful lives, each part is depreciated separately. The depreciable amount is the asset's carrying amount less its residual value at the end of its useful life, if it is significant and can be reasonably determined. Land is not depreciated, even when acquired together with a building. Tangible assets held for sale are not depreciated (see the accounting policy for "Assets held for sale and discontinued operations"). Changes in the asset's useful life, in its residual value or in the pattern of consumption of the future economic benefits embodied in the asset, are accounted for prospectively.

Assets to be handed over for no consideration are depreciated over the shorter term between the duration of the concession or the asset's useful life.

Replacement costs of identifiable parts in complex assets are capitalised and depreciated over their useful life; the residual carrying amount of the part that has been substituted is charged to the profit and loss account. Leasehold improvement costs are depreciated over the useful life of the improvements or, if lower, over the residual length of the lease, considering any renewal period if renewal depends entirely on the lessee and is virtually certain. Expenditures for ordinary maintenance and repairs are recognised as an expense as incurred.

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(12) These liabilities relate essentially to assets in the Exploration & Production segment. Decommissioning and restoration liabilities associated with tangible assets of Refining & Marketing and Chemical and Gas & Power segments are recognised when the cost is actually incurred and the amount of the liability can be reliably estimated, considering that undetermined settlement dates for assets dismantlement and restoration do not allow a discounting estimate of the obligation. With regard to this, Eni performs periodic reviews of its tangible assets of Refining & Marketing and Chemical and Gas & Power segments for any changes in facts and circumstances that might require recognition of a decommissioning and restoration liability.

The carrying amount of property, plant and equipment is reviewed for impairment whenever there is any indication that the carrying amounts of those assets may not be recoverable. The recoverability of an asset is assessed by comparing its carrying amount with the recoverable amount, which is the higher of the asset's fair value less costs of disposal and its value in use. Value in use is the present value of the future cash flows expected to be derived from continuing use of the asset and, if significant and reliably measurable, the cash flows expected to be obtained from its disposal at the end of its useful life, after deducting the costs of disposal. Expected cash flows are determined on the basis of reasonable and supportable assumptions that represent management's best estimate of the range of economic conditions that will exist over the remaining useful life of the asset, giving greater weight to external evidence.

With reference to commodity prices, management assumes the price scenario adopted for economic and financial projections and for whole life appraisal for capital expenditures. In particular, for the cash flows associated to oil, natural gas and petroleum products prices (and prices derived from them), the price scenario is approved by the Board of Directors and is based on management's planning assumptions, in the short and medium term, takes into account the projections of market analysts and, if there is a sufficient liquidity and reliability level, on the forward prices prevailing in the marketplace.

Discounting is carried out at a rate that reflects a current market assessment of the time value of money and of the risks specific to the asset that are not reflected in the expected future cash flows. In particular, the discount rate used is the Weighted Average Cost of Capital (WACC) adjusted for the specific country risk of the asset. These adjustments are measured considering information from external parties. WACC differs considering the risk associated with each operating segments where the asset operates. In particular, for the assets belonging to the Gas & Power segment and the Chemical business, taking into account their different risk compared with Eni as a whole, specific WACC rates have been defined on the basis of a sample of companies operating in the same segment/business, adjusted to take into consideration the risk premium of the specific country of the activity. For the other segments/businesses, a single WACC is used considering that the risk is the same to that of Eni as a whole. Value in use is calculated net of the tax effect as this method results in values similar to those resulting from discounting pre-tax cash flows at a pre-tax discount rate deriving, through an iteration process, from a post-tax valuation. Valuation is carried out for each single asset or, if the recoverable amount of a single asset cannot be determined, for the smallest identifiable group of assets that generates independent cash inflows from their continuous use, the so-called "cash-generating unit". When an impairment loss no longer exists or has decreased, a reversal of the impairment loss is recognised in the profit and loss account. The impairment reversal shall not exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

The carrying amount of property, plant and equipment is derecognised on disposal or when no future economic benefits are expected from its use or disposal; the arising gain or loss is recognised in the profit and loss account.

Intangible assets

Intangible assets are identifiable non-monetary assets without physical substance, controlled by the Company and able to produce future economic benefits, and goodwill. An asset is classified as intangible when management is able to distinguish it clearly from goodwill. This condition is normally met when: (i) the intangible asset arises from contractual or other legal rights, or (ii) the asset is separable, i.e. can be sold, transferred, licensed, rented or exchanged, either individually or together with other assets. An entity controls an intangible asset if it has the power to obtain the future economic benefits flowing from the underlying asset and to restrict the access of others to those benefits.

Intangible assets are initially recognised at cost as determined by the criteria used for tangible assets and they are not revalued for financial reporting purposes.

Intangible assets with finite useful lives are amortised on a systematic basis over their useful life; the amount to be amortised and the recoverability of the carrying amount are determined in accordance with the criteria described in the accounting policy for "Property, plant and equipment".

Goodwill and intangible assets with indefinite useful lives are not amortised. Their carrying amounts are tested for impairment at least annually and whenever there is any indication of impairment. Goodwill is tested for impairment at the lowest level within the entity at which it is monitored for internal management purposes. When the carrying amount of the cash-generating unit, including goodwill allocated thereto, calculated considering any impairment loss of the non-current assets belonging to the cash-generating unit, exceeds its recoverable amount[13], the excess is recognised as an impairment loss. The impairment loss is allocated first to reduce the carrying amount of goodwill; any remaining excess is allocated to the other assets of the unit pro-rata on the basis of the carrying amount of each asset in the unit, up to the recoverable amount of assets with finite useful lives. An impairment loss recognised for goodwill is not reversed in a subsequent period[14].

Costs of obtaining a contract with a customer are recognised in the balance sheet if the Company expects to recover those costs. The intangible asset arising from those costs is amortised on a systematic basis, that is consistent with the transfer to the customer of the goods or services to which the asset relates, and is tested for impairment.[15]

Costs of technological development activities are capitalised when: (i) the cost attributable to the development activity can be measured reliably; (ii) there is the intention and the availability of financial and technical resources to make the asset available for use or sale; and (iii) it can be demonstrated that the asset is able to generate probable future economic benefits.

The carrying amount of intangible assets is derecognised on disposal or when no future economic benefits are expected from its use or disposal; any arising gain or loss is recognised in the profit and loss account.

Grants related to assets

Government grants related to assets are recognised by deducting them in calculating the carrying amount of the related assets when there is reasonable assurance that the Company will comply with the conditions attaching to them and the grants will be received.

Inventories

Inventories, including compulsory stock, are measured at the lower of purchase or production cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale, or, with reference to inventories of crude oil and petroleum products already included in binding sale contracts, the contractual selling price. Inventories which are principally acquired with the purpose of selling in the near future and generating a profit from fluctuations in price are measured at fair value less costs to sell. Materials and other supplies held for use in production are not written down below cost if the finished products in which they will be incorporated are expected to be sold at or above cost.

The cost of inventories of hydrocarbons (crude oil, condensates and natural gas) and petroleum products is determined by applying the weighted average cost method on a three-month basis, or on a different time period (e.g. monthly), when it is justified by the use and the turnover of inventories of crude oil and petroleum products; the cost of inventories of the Chemical business is determined by applying the weighted average cost on an annual basis.

When take-or-pay clauses are included in long-term gas purchase contracts, pre-paid gas volumes that are not withdrawn to fulfill minimum annual take obligations, are measured using the pricing formulas contractually defined. They are recognised under “Other assets” as “Deferred costs” as a contra to “Other payables” or, after the settlement, to “Cash and cash equivalents”. The allocated deferred costs are charged to the profit and loss account: (i) when natural gas is actually withdrawn — the related cost is included in the determination of the weighted average cost of inventories; and (ii) for the portion which is not recoverable, when it is not possible to withdraw the previously pre-paid gas, within the contractually defined deadlines. Furthermore, the allocated deferred costs are tested for economic recoverability by comparing the related carrying amount and their net realisable value, determined adopting the same criteria described for inventories.

(13) For the definition of recoverable amount see the accounting policy for “Property, plant and equipment”.

(14) Impairment losses recognised in an interim period are not reversed also when, considering conditions existing in a subsequent interim period, they would have been recognised in a smaller amount or would not have been recognised.

(15) The previous accounting policies required the capitalisation of directly attributable customer acquisition costs when the following conditions are met: (i) the capitalised costs can be measured reliably; (ii) there is a contract binding the customer for a specified period of time; and (iii) it is probable that the costs will be recovered through the revenue from the sales, or, where the customer withdraws from the contract in advance, through the collection of a penalty.

Significant accounting estimates and judgements: impairment of non-financial assets

Non-financial assets are impaired whenever events or changes in circumstances indicate that carrying amounts of the assets are not recoverable. Such impairment indicators include changes in the Group's business plans, changes in commodity prices leading to unprofitable performance, a reduced capacity utilisation of plants and, for oil&gas properties, significant downward revisions of estimated proved reserve quantities or significant increase of the estimated development costs. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain and complex matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for demand and supply conditions on a global or regional scale. Similar remarks are valid for assessing the physical recoverability of assets recognised in the balance sheet (deferred costs — see also the accounting policy for "Inventories") related to natural gas volumes not withdrawn under long-term supply contracts with take-or-pay clauses, as well as for assessing the recoverability of deferred tax assets (see also accounting policy for "Income taxes"), which requires complex processes for evaluating the existence of adequate future taxable profit.

The expected future cash flows used for impairment analyses are based on judgemental assessments of future production volumes, prices and costs, considering available information at the date of review and are discounted by using a rate which considers the risks specific to the asset.

For oil and natural gas properties, the expected future cash flows are estimated principally based on developed and undeveloped proved reserves including, among other elements, production taxes and the costs to be incurred for the reserves yet to be developed. The estimate of the future amount of production is based on assumptions related to the commodity future prices, lifting and development costs, field decline rates, market demand and other factors. The cash flows associated to oil&gas commodities are estimated on the basis of forward market information, if there is a sufficient liquidity and reliability level, on the consensus of independent specialised analysts and on management's forecasts about the evolution of the supply and demand fundamentals.

Financial instruments[16]

Financial assets

Financial assets are classified, on the basis of both contractual cash flow characteristics and the entity's business model for managing them, in the following categories: (i) financial assets measured at amortised cost; (ii) financial assets measured at fair value through other comprehensive income (hereinafter also OCI); (iii) financial assets measured at fair value through profit or loss.

At initial recognition, a financial asset is measured at its fair value; at initial recognition, trade receivables that do not have a significant financing component are measured at their transaction price.

After initial recognition, financial assets whose contractual terms give rise to cash flows that are solely payments of principal and interest on the principal amount outstanding are measured at amortised cost if they are held within a business model whose objective is to hold financial assets in order to collect contractual cash flows (the so-called hold to collect business model). For financial assets measured at amortised cost, interest income determined using the effective interest rate, foreign exchange differences and any impairment losses[17] (see the accounting policy for "Impairment of financial assets") are recognised in the profit and loss account.

Conversely, financial assets that are debt instruments are measured at fair value through OCI (hereinafter also FVTOCI) if they are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets (the so-called hold to collect and sell business model). In these cases: (i) interest income determined using the effective interest rate, foreign exchange

(16) The accounting policies related to financial instruments were defined on the basis of IFRS 9 "Financial Instruments" effective from 2018; as required by the standard, the new requirements have been applied starting from January 1, 2018 without restating the prior years under comparison. With reference to the financial instruments held by the Company, the previous accounting policies (see 2017 Annual Report on Form 20-F) required essentially: (i) the classification of financial assets on the basis of the categories under IAS 39; (ii) recognition and measurement of impairment losses if there was objective evidence that an impairment loss had been incurred (the so-called incurred loss model); and (iii) more stringent hedge accounting requirements (mainly referred to the assessment of hedge effectiveness).

(17) Receivables and other financial assets measured at amortised cost are presented in the balance sheet net of their loss allowance.

differences and any impairment losses (see the accounting policy for "Impairment of financial assets") are recognised in the profit and loss account; (ii) changes in fair value of the instruments are recognised in equity, within other comprehensive income. The accumulated changes in fair value, recognised in the equity reserve related to other comprehensive income, is reclassified to the profit and loss account when the financial asset is derecognised.

A financial asset represented by a debt instrument that is neither measured at amortised cost nor at FVTOCI, is measured at fair value through profit or loss (hereinafter FVTPL); financial assets held for trading fall into this category. Interest income on assets held for trading contributes to the fair value measurement of the instrument and is recognised in "Finance income (expense)", within "Net finance income (expense) from financial assets held for trading".

When the purchase or sale of a financial asset is under a contract whose terms require delivery of the asset within the time frame established generally by regulation or convention in the marketplace concerned, the transaction is accounted for on the settlement date.

Impairment of financial assets

The expected credit loss model is adopted for the impairment of financial assets that are debt instruments, but are not measured at fair value through profit or loss.

In particular, the expected credit losses are generally measured by multiplying: (i) the exposure to the counterparty's credit risk net of any collateral held and other credit enhancements (Exposure At Default, EAD); (ii) the probability that the default of the counterparty occurs (Probability of Default, PD); and (iii) the percentage estimate of the exposure that will not be recovered in case of default (LGD), considering the past experiences and the range of recovery tools that can be activated (e.g. extrajudicial and/or legal proceedings, etc.).

With reference to trade and other receivables, Probabilities of Default of counterparties are determined by adopting the internal credit ratings already used for credit worthiness and are periodically reviewed using, inter alia, back-testing analyses; for government entities (e.g. National Oil Companies), the Probability of Default, represented essentially by the probability of a delayed payment, is determined by using, as input data, the country risk premium adopted to determine WACC for the impairment review of non-financial assets.

For customers without internal credit ratings, the expected credit losses are measured by using a provision matrix, defined by grouping, where appropriate, receivables into adequate clusters to which apply expected loss rates defined on the basis of their historical credit loss experiences, adjusted, where appropriate, to take into account forward-looking information on credit risk of the counterparty or clusters of counterparties.[18]

Considering the characteristics of the reference markets, financial assets with more than 180 days past due or, in any case, with counterparties undergoing litigation, restructuring or renegotiation, are considered to be in default. Counterparties are considered undergoing litigation when judicial/legal proceedings aimed to recover a receivable have been activated or are going to be activated. Impairment losses of trade and other receivables are recognised in the profit and loss account, net of any impairment reversal, within the line item of the profit and loss account "Net (impairment losses) reversals of trade and other receivables".

The financing receivables held for operating purposes, granted to associates and joint ventures, which in substance form part of the entity's net investment in these investees, are tested for impairment considering also the underlying industrial operations and the macroeconomic scenarios of the countries where the investees operate.

(18) For exposures arising from intragroup transactions, the recovery rate is assumed equal to 100% taking into account the possibility to providecapital injections of investees.

Significant accounting estimates and judgements: impairment of financial assets

Measuring impairment losses of financial assets requires management evaluation of complex and highly uncertain elements such as, for example, Probabilities of Default of counterparties, the existence of any collaterals or other credit enhancements, the expected exposure that will not be recovered in case of default, as well as the definition of customers' clusters to be adopted.

Investments in equity instruments

Investments in equity instruments, that are not held for trading, are measured at fair value through other comprehensive income, without subsequent transfer of fair value changes to profit or loss on derecognition of these investments; conversely, dividends from these investments are recognised in the profit and loss account, within the line item "Income (Expense) from investments". In limited circumstances, an investment in equity instruments can be measured at cost if it is an appropriate estimate of fair value

Financial liabilities

At initial recognition, financial liabilities, other than derivative financial instruments, are measured at their fair value, minus transaction costs that are directly attributable, and are subsequently measured at amortised cost.

Derivative financial instruments and hedge accounting

Derivative financial instruments, including embedded derivatives (see below) that are separated from the host contract, are assets and liabilities measured at their fair value.

With reference to the defined risk management objectives and strategy, the qualifying criteria for hedge accounting requires: (i) the existence of an economic relationship between the hedged item and the hedging instrument in order to offset the related value changes and the effects of counterparty credit risk do not dominate the economic relationship between the hedged item and the hedging instrument; and (ii) the definition of the relationship between the quantity of the hedged item and the quantity of the hedging instrument (the so-called hedge ratio) consistently with the entity's risk management objectives, under a defined risk management strategy; the hedge ratio is adjusted, where appropriate, after taking into account any adequate rebalancing. A hedging relationship is discontinued prospectively, in its entirety or a part of it, when it no longer meets the risk management objectives on the basis of which it qualified for hedge accounting, it ceases to meet the other qualifying criteria or after rebalancing it.

When derivatives hedge the risk of changes in the fair value of the hedged items (fair value hedge, e.g. hedging of the variability in the fair value of fixed interest rate assets/liabilities), the derivatives are measured at fair value through profit and loss account. Consistently, the carrying amount of the hedged item is adjusted to reflect, in the profit and loss account, the changes in fair value of the hedged item attributable to the hedged risk; this applies even if the hedged item should be otherwise measured.

When derivatives hedge the exposure to variability in cash flows of the hedged items (cash flow hedge, e.g. hedging the variability in the cash flows of assets/liabilities as a result of the fluctuations of exchange rate), the effective changes in the fair value of the derivatives are initially recognised in the equity reserve related to other comprehensive income and then reclassified to the profit and loss account in the same period during which the hedged transaction affects the profit and loss account.

If a hedged forecast transaction subsequently results in the recognition of a non-financial asset or a non-financial liability, the accumulated changes in fair value of hedging derivatives, recognised in equity, are included directly in the carrying amount of the hedged non-financial asset/liability (commonly referred to as a "basis adjustment").

The changes in the fair value of derivatives, that are not designated as hedging instruments, including any ineffective portion of changes in fair value of hedging derivatives, are recognised in the profit and loss account. In particular, the changes in the fair value of non-hedging derivatives on interest rates and exchange rates are recognised in the profit and loss account line item "Finance income (expense)"; conversely, the changes in the fair value of non-hedging derivatives on commodities are recognised in the profit and loss account line item "Other operating (expense) income".

Derivatives embedded in financial assets are no longer accounted for separately; in such circumstances, the entire hybrid instrument is classified depending on the contractual cash flow characteristics of the financial instrument and the business model for managing it (see the accounting policy for "Financial assets"). Derivatives embedded in financial liabilities and/or non-financial assets are separated if: (i) the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract; (ii) a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative; and (iii) the entire hybrid contract is not measured at FVTPL.

The entity assesses the existence of embedded derivatives to be separated when it becomes party to the contract and, afterwards, when a change in the terms of the contract that modifies its cash flows occurs.

Contracts to buy or sell commodities entered into and continue to be held for the purpose of their receipt or delivery in accordance with the Group's expected purchase, sale or usage requirements are recognised on an accrual basis (the so-called normal sale and normal purchase exemption or own use exemption).

Offsetting of financial assets and liabilities

Financial assets and liabilities are set off in the balance sheet if the Group currently has a legally enforceable right to set off and intends to settle on a net basis (or to realise the asset and settle the liability simultaneously).

Derecognition of financial assets and liabilities

Transferred financial assets are derecognised when the contractual rights to receive the cash flows from the financial assets expire or are transferred to another party. Financial liabilities are derecognised when they are extinguished, or when the obligation specified in the contract is discharged, cancelled or expired.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, demand deposits, as well as financial assets originally due, generally, within 90 days, readily convertible to known amount of cash and subject to an insignificant risk of changes in value.

Provisions, contingent liabilities and contingent assets

A provision is a liability of uncertain timing or amount on the balance sheet date. Provisions are recognised when: (i) there is a present obligation, legal or constructive, as a result of a past event; (ii) it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation; and (iii) the amount of the obligation can be reliably estimated. The amount recognised as a provision is the best estimate of the expenditure required to settle the present obligation or to transfer it to third parties at the balance sheet date. The amount recognised for onerous contracts is the lower of the cost necessary to fulfill the obligations, net of expected economic benefits deriving from the contracts, and any compensation or penalties arising from failure to fulfill these obligations. Where the effect of the time value is material, and the payment date of the obligations can be reasonably estimated, provisions to be accrued are the present value of the expenditures expected to be required to settle the obligation at a discount rate that reflects the Company's average borrowing rate taking into account the risks associated with the obligation. The increase in the provision due to the passage of time is recognised as "Finance income (expense)".

Where an obligation exists for an item of property, plant and equipment (e.g. site dismantling and restoration), the provision is recognised together with a corresponding amount as part of the related item of property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset.

A provision for restructuring costs is recognised only when the Company has a detailed formal plan for the restructuring and has raised a valid expectation in the affected parties that it will carry out the restructuring.

Provisions are periodically reviewed and adjusted to reflect changes in the estimates of costs, timing and discount rates. Changes in provisions are recognised in the same profit and loss account line item where the original provision was charged, or, when the liability regards tangible assets (e.g. site dismantling and restoration), changes in the provision are recognised with a corresponding entry to the assets to which they refer, to the extent of the assets' carrying amounts; any excess amount is recognised in the profit and loss account.

Contingent liabilities are: (i) possible, but not probable obligations arising from past events, whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company; or (ii) present obligations arising from past events, whose amount cannot be reliably measured or whose settlement will probably not result in an outflow of resources embodying economic benefits. Contingent liabilities are not recognised in the financial statements, but are disclosed.

Contingent assets, that are possible assets arising from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company, are not recognised unless the realisation of economic benefits is virtually certain. Contingent assets are disclosed when an inflow of economic benefits is probable. Contingent assets are assessed periodically to ensure that developments are appropriately reflected in the financial statements; if it has become virtually certain that an inflow of economic benefits will arise, the asset and the related income are recognised in the financial statements of the period in which the change occurs.

Significant accounting estimates and judgements: decommissioning and restoration liabilities, environmental liabilities and other provisions

The Group holds provisions for dismantling and removing items of property, plant and equipment, and restoring land or seabed at the end of the oil and gas production activity. Estimating obligations to dismantle, remove and restore items of property, plant and equipment is complex. It requires management to make estimates and judgements with respect to removal obligations that will come to term many years into the future and contracts and regulations are often unclear as to what constitutes removal. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known as asset removal technologies and costs constantly evolve in the countries where Eni operates, as do political, environmental, safety and public expectations.

Where the effect of the time value of money is material, the amount recognised as provision is the present value of expenditures expected to be required to settle the obligation. After the initial recognition, the carrying amount of decommissioning and restoration liabilities is adjusted to reflect the passage of time and any change in the estimates following the modification of amount and timing of future cash flows and discount rates adopted. The discount rate used to determine the provision is based on complex managerial judgements.

As other oil&gas companies, Eni is subject to numerous EU, national, regional and local environmental laws and regulations concerning its oil&gas operations, production and other activities. They include legislations that implement international conventions or protocols. Environmental provisions are recognised when it becomes probable that an outflow of resources will be required to settle the obligation and such obligation can be reliably estimated. Management, considering the actions already taken, insurance policies obtained to cover environmental risks and provision for risks accrued, does not expect any material adverse effect on Eni's consolidated results of operations and financial position as a result of such laws and regulations. However, there can be no assurance that there will not be a material adverse impact on Eni's consolidated results of operations and financial position due to: (i) the possibility of an unknown contamination; (ii) the results of the ongoing surveys and other possible effects of statements required by applicable laws; (iii) the possible effects of future environmental legislations and rules; (iv) the effects of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni's liability, if any, against other potentially responsible parties with respect to such litigations and the possible reimbursements.

In addition to liabilities related to environmental and decommissioning and restoration liabilities, Eni recognises provisions primarily related to legal, trade and tax proceedings. These provisions are estimated on the basis of complex managerial judgements related to the amounts to be recognised and the timing of future cash outflows. After the initial recognition, provisions are periodically reviewed and adjusted to reflect the current best estimate.

Employee benefits

Employee benefits are considerations given by the Group in exchange for service rendered by employees or for the termination of employment.

Post-employment benefit plans, including informal arrangements, are classified as either defined contribution plans or defined benefit plans depending on the economic substance of the plan as derived from its principal terms and conditions. Under defined contribution plans, the Company's obligation, which consists in making payments to the State or to a trust or a fund, is determined on the basis of contributions due.

The liabilities related to defined benefit plans, net of any plan assets, are determined on the basis of actuarial assumptions and charged on an accrual basis during the employment period required to obtain the benefits.

Net interest includes the return on plan assets and the interests cost to be recognised in the profit and loss account. Net interest is measured by applying to the liability, net of any plan assets, the discount rate used to calculate the present value of the liability; net interest of defined benefit plans is recognised in "Finance income (expense)".

Re-measurements of the net defined benefit liability, comprising actuarial gains and losses, resulting from changes in the actuarial assumptions used or from changes arising from experience adjustments, and the return on plan assets excluding amounts included in net interest, are recognised within the statement of comprehensive income. Re-measurements of the net defined benefit liability, recognised whithin other comprehensive income, are not reclassified subsequently to the profit and loss account .

Obligations for long-term benefits are determined by adopting actuarial assumptions. The effects of re-measurements are taken to profit and loss account in their entirety.

Share-based payments

The line item "Payroll and related costs" includes the cost of the share-based incentive plan, consistently with its actual remunerative nature.[19] The cost of the share-based incentive plan is measured by reference to the fair value of the equity instruments granted and the estimate of the number of shares that eventually vest; the cost is recognised on an accrual basis pro rata temporis over the vesting period, that is the period between the grant date and the settlement date. The fair value of the shares underlying the incentive plan is measured at the grant date, taking into account the estimate of achievement of market conditions (e.g. Total Shareholder Return), and is not adjusted in subsequent periods; when the achievement is linked also to non-market conditions, the number of shares expected to vest is adjusted during the vesting period to reflect the updated estimate of these conditions. If, at the end of the vesting period, the incentive plan does not vest because of failure to satisfy the performance conditions, the portion of cost related to market conditions is not reversed to the profit and loss account.

Significant accounting estimates and judgements: employee benefits and share-based payments

Defined benefit plans are evaluated with reference to uncertain events and based upon actuarial assumptions including, among others, discount rates, expected rates of salary increases, mortality rates, estimated retirement dates and medical cost trends. The significant assumptions used to account for defined benefit plans are determined as follows: (i) discount and inflation rates are based on the market yields on high quality corporate bonds (or, in the absence of a deep market of these bonds, on the market yields on government bonds) and on the expected inflation rates in the reference currency area; (ii) the future salary levels of the individual employees are determined including an estimate of future changes attributed

(19) The current share-based incentive plan, to be settled by treasury shares, was approved by the shareholders' meeting held on April 13, 2017.

to general price levels (consistent with inflation rate assumptions), productivity, seniority and promotion; (iii) healthcare cost trend assumptions reflect an estimate of the actual future changes in the cost of the healthcare related benefits provided to the plan participants and are based on past and current healthcare cost trends, including healthcare inflation, changes in healthcare utilisation and changes in health status of the participants; and (iv) demographic assumptions such as mortality, disability and turnover reflect the best estimate of these future events for individual employees involved.

Differences in the amount of the net defined benefit liability (asset), deriving from the re-measurements, comprising, among others, changes in the current actuarial assumptions, differences in the previous actuarial assumptions and what has actually occurred and differences in the return on plan assets, excluding amounts included in net interest, usually occur. Similarly to the approach followed for the fair value measurement of financial instruments, the fair value of the shares underlying the incentive plans is measured by using complex valuation techniques and identifying, through structured judgements, the assumptions to be adopted.

Treasury shares

Treasury shares, including shares held to meet the future requirements of the share-based incentive plans, are recognised as deductions from equity at cost. Any gain or loss resulting from subsequent sales is recognised in equity.

Revenue from contracts with customers[20]

Revenue from contracts with customers is recognised on the basis of the following five steps: (i) identifying the contract with the customer; (ii) identifying the performance obligations, that are promises in a contract to transfer goods and/or services to a customer; (iii) determining the transaction price; (iv) allocating the transaction price to each performance obligation on the basis of the relative stand-alone selling prices of each good or service; and (v) recognising revenue when (or as) a performance obligation is satisfied, that is when a promised good or service is transferred to a customer. A promised good or service is transferred when (or as) the customer obtains control of it. Control can be transferred over time or at a point in time. With reference to the most important products sold by Eni, revenue is generally recognised for:

- crude oil, upon shipment;
- natural gas and electricity, upon delivery to the customer;
- petroleum products sold to retail distribution networks, upon delivery to the service stations, whereas all other sales of petroleum products are recognised upon shipment; and
- chemical products and other products, upon shipment.

Revenue from crude oil and natural gas production from properties in which Eni has an interest together with other producers is recognised on the basis of the quantities actually lifted and sold (sales method); costs are recognised on the basis of the quantities actually sold.[21] Revenue is measured at the fair value of the consideration to which the Company expects to be entitled in exchange for transferring promised goods and/or services to a customer, excluding amounts collected on behalf of third parties. In determining the transaction price, the promised amount of consideration is adjusted for the effects of the time value of money if the timing of payments agreed to by the parties to the contract provides the customer or the entity with a significant benefit of financing the transfer of goods or services to the customer. The promised amount of consideration is not adjusted for the effect of the significant financing component if, at contract inception, it is expected that the period between the transfer of a promised good or service to a customer and when the customer pays for that good or service will be one year or less. If the consideration promised in a contract includes a variable amount, the Company estimates the amount of consideration to which it will be entitled in exchange for transferring the promised goods and/or services to a customer; in particular, the amount of consideration can vary because of discounts, refunds, incentives, price concessions, performance bonuses, penalties or if the price is contingent on the occurrence or non-occurrence of future events.

(20) The previous accounting policies about revenue are described in the 2017 Annual Report on Form 20-F.

(21) In accordance with the previous accounting policy (entitlement method), revenue from crude oil and natural gas production from properties in which Eni has an interest together with other producers were recognised on the basis of Eni's net working interest in those properties. In the balance sheet, lifting imbalances were recognised respectively as payables and receivables and measured at current prices at the balance sheet date.

If, in a contract, the Company grants a customer the option to acquire additional goods or services for free or at a discount (for example sales incentives, customer award points, etc.), this option gives rise to a separate performance obligation in the contract only if the option provides a material right to the customer that it would not receive without entering into that contract.

When goods or services are exchanged for goods or services which are of a similar nature and value, the exchange is not regarded as a transaction which generates revenue.

Significant accounting estimates and judgements: revenue from contracts with customers

Revenue from sales of electricity and gas to retail customers includes amount accrued for electricity and gas supplied between the date of the last invoiced meter reading (actual or estimated) of volumes consumed and the end of the year. These estimates consider information provided by the grid managers about the volumes allocated among the customers of the secondary distribution network, about the actual and estimated volumes consumed by customers, as well as they rely on other factors, considered by the management, which can impact on them. Therefore, revenue is accrued as a result of a complex estimate based on the volumes distributed and allocated, communicated by third parties, likely to be adjusted, according to applicable regulations, within the fifth year following the one in which they are accrued. Considering the contractual obligations on the supply delivery points, revenue from sales of electricity and gas to retail customers includes costs for transportation and dispatching and in these cases the gross amount of consideration to which the entity is entitled is recognised.

Costs

Costs are recognised when the related goods and services are sold or consumed during the year, when they are allocated on a systematic basis or when their future economic benefits cannot be identified. Costs associated with emission quotas, determined on the basis of the market prices, are recognised in relation to the amounts of the carbon dioxide emissions that exceed free allowances. Costs related to the purchase of the emission rights that exceed the amount necessary to meet regulatory obligations, are recognised as intangible assets. Revenue related to emission quotas is recognised when they are sold and, if applicable, purchased emission rights are considered the first to be sold. Monetary receivables granted to replace the free award emission rights are recognised as a contra to the line item “Other income and revenues”.

Lease payments under an operating lease are recognised as an expense over the lease term. The costs for the acquisition of new knowledge or discoveries, the study of products or alternative processes, new techniques or models, the planning and construction of prototypes or, in any case, costs incurred for other scientific research activities or technological development, which cannot be capitalised (see also the accounting policy for “Intangible assets”), are included in the profit and loss account when they are incurred.

Exchange differences

Revenues and costs associated with transactions in foreign currencies are translated into the functional currency by applying the exchange rate at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated into the functional currency at the spot exchange rate on the balance sheet date and any resulting exchange differences are included in the profit and loss account within “Finance income (expense)” or, if designated as hedging instruments for the foreign currency risk, in the same line item in which the economic effects of the hedged item are recognised. Non-monetary assets and liabilities denominated in foreign currencies, measured at cost, are not retranslated subsequent to initial recognition. Non-monetary items measured at fair value, recoverable amount or net realisable value are retranslated using the exchange rate at the date when the value is determined.

Dividends

Dividends are recognised at the date of the general shareholders’ meeting in which they were declared, except when the sale of shares before the ex-dividend date is certain.

Income taxes

Current income taxes are determined on the basis of estimated taxable profit. The estimated liability is included in “Income tax payables”. Current income tax assets and liabilities are measured at the amount expected to be paid to (recovered from) the taxation authorities, using tax rates and the tax laws that have been enacted or substantively enacted by the end of the reporting period. Deferred tax assets and liabilities are recognised for temporary differences arising between the carrying amounts of the assets and liabilities and their tax bases, based on tax rates and tax laws that are expected to apply to the period when the asset is realised or the liability is settled, based on tax rates and tax laws that have been enacted or substantively enacted by the end of the reporting period. Deferred tax assets are recognised when their recoverability is considered probable, i.e. when it is probable that sufficient taxable profit will be available in the same year as the reversal of the deductible temporary difference. Similarly, deferred tax assets for the carry-forward of unused tax credits and unused tax losses are recognised to the extent that their recoverability is probable. The carrying amount of the deferred tax assets is reviewed, at least, on an annual basis. Income tax assets, that are uncertain in the amount to be recovered, are recognised in accordance with the probable threshold.

Relating to the taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint arrangements, the related deferred tax liabilities are not recognised if the investor is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future. Deferred tax assets and liabilities are presented within non-current assets and liabilities and are offset at a single entity level if related to off-settable taxes. The balance of the offset, if positive, is recognised in the line item "Deferred tax assets" and, if negative, in the line item "Deferred tax liabilities". When the results of transactions are recognised directly in shareholders' equity, the related current and deferred taxes are also charged to the shareholders' equity.

Assets held for sale and discontinued operations

Non-current assets and current and non-current assets included within disposal groups, are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through their continuing use. This condition is regarded as met only when the sale is highly probable and the asset or the disposal group is available for immediate sale in its present condition. When there is a sale plan involving loss of control of a subsidiary, all the assets and liabilities of that subsidiary are classified as held for sale, regardless of whether a non-controlling interest in its former subsidiary will be retained after the sale.

Non-current assets held for sale, current and non-current assets included within disposal groups that have been classified as held for sale and the liabilities directly associated with them are recognised in the balance sheet separately from other assets and liabilities.

Immediately before the initial classification of a non-current asset and/or a disposal group as held for sale, the non-current asset and/or the assets and liabilities in the disposal group are measured in accordance with applicable IFRSs. Subsequently, non-current assets held for sale are not depreciated or amortised and they are measured at the lower of the fair value less costs to sell and their carrying amount. If an equity-accounted investment, or a portion of that investment meets the criteria to be classified as held for sale, it is no longer accounted for using the equity method; and is measured at the lower of its carrying amount at the date the equity method is discontinued, and its fair value less costs to sell. Any retained portion of the equity-accounted investment that has not been classified as held for sale is accounted for using the equity method until disposal of the portion that is classified as held for sale takes place. After the disposal takes place, any retained interest in the investee is measured in accordance with the measurement criteria indicated in the accounting policy for "— Investments in equity instruments", unless the retained interest continues to be an equity-accounted investment.

Any difference between the carrying amount of the non-current assets and the fair value less costs to sell is taken to the profit and loss account as an impairment loss; any subsequent reversal is recognised up to the cumulative impairment losses, including those recognised prior to qualification of the asset as held for sale. Non-current assets classified as held for sale and disposal groups, are considered a discontinued operation if, alternatively: (i) represent a separate major line of business or geographical area of operations; (ii) are part of a disposal program of a separate major line of business or geographical area of operations; or (iii) are a subsidiary acquired exclusively with a view to resale. The results of discontinued operations, as well as any gain or loss recognised on the disposal, are indicated in a separate line item of the profit and loss account, net of the related tax effects; the economic figures of discontinued operations are indicated also for prior periods presented in the financial statements.

If events or circumstances occur that no longer allow to classify a non-current asset or a disposal group as held for sale, the non-current asset or the disposal group is reclassified into the original line items of the balance sheet and measured at the lower of: (i) its carrying amount at the date of classification as held for sale adjusted for any depreciation, amortisations impairment losses and reversals that would have been recognised had the asset or disposal group not been classified as held for sale, and (ii) its recoverable amount at the date of the subsequent decision not to sell. If the interruption of a plan of sale concerns a subsidiary, joint operation, joint venture, associate, or a portion of an interest in a joint venture or an associate, financial statements for the period since classification as held for sale are amended.

Fair value measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants (not in a forced liquidation or a distress sale) at the measurement date (exit price). Fair value measurement is based on the market conditions existing at the measurement date and on the assumptions of market participants (market-based measurement). A fair value measurement assumes that the transaction to sell the asset or transfer the liability takes place in the principal market for the asset or liability, or in the absence of a principal market, in the most advantageous market to which the entity has access, independently from the entity's intention to sell the asset or transfer the liability to be measured.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. Highest and best use is determined from the perspective of market participants, even if the entity intends a different use; an entity's current use of a non-financial asset is presumed to be its highest and best use, unless market or other factors suggest that a different use by market participants would maximise the value of the asset.

The fair value of a liability, both financial and non-financial, or of the Company's own equity instrument, in the absence of a quoted price, is measured from the perspective of a market participant that holds the identical item as an asset at the measurement date. The fair value of financial instruments takes into account the counterparty's credit risk for a financial asset (Credit Valuation Adjustment, CVA) and the Company's own credit risk for a financial liability (Debit Valuation Adjustment, DVA).

In the absence of available market quotation, fair value is measured by using valuation techniques that are appropriate in the circumstances, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

Significant accounting estimates and judgements: fair value

Fair value measurement, although based on the best available information and on the use of appropriate valuation techniques, is inherently uncertain, requires the use of professional judgement and could result in expected values other than the actual ones.

2 Financial statements[22]

Assets and liabilities on the balance sheet are classified as current and non-current. Items on the profit and loss account are presented by nature[23]. Assets and liabilities are classified as current when: (i) they are expected to be realised/settled in the entity's normal operating cycle or within twelve months after the balance sheet date; (ii) they are cash or cash equivalents unless they are restricted from being exchanged or used to settle a liability for at least twelve months after the balance sheet date; or (iii) they are held primarily for the purpose of trading. Derivative financial instruments held for trading are classified as current, apart from their maturity date. Non hedging derivative financial instruments, which are entered

(22) The impacts on the financial statements arising from the adoption, starting from January 1, 2018, of the new IFRSs, as well as the other changes in the financial statements are described in note 3 — Changes in accounting policies

(23) Further information about classification of financial instruments is provided in note 27 — Guarantees, commitments and risks — Other information about financial instruments.

into to manage risk exposures but do not satisfy the formal requirements to be considered as hedging, and hedging derivative financial instruments are classified as current when they are expected to be realised/settled within twelve months after the balance sheet date; on the contrary they are classified as non-current.

The statement of comprehensive income (loss) shows net profit integrated with income and expenses that are not recognised directly in the profit and loss account according to IFRSs.

The statement of changes in shareholders' equity includes the total comprehensive income (loss) for the year, transactions with shareholders in their capacity as shareholders and other changes in shareholders' equity.

The statement of cash flows is presented using the indirect method, whereby net profit (loss) is adjusted for the effects of non-cash transactions.

3 Changes in accounting policies

IFRS 15 "Revenue from Contracts with Customers", as well as the document "Clarifications to IFRS 15 Revenue from Contracts with Customers", which set out the requirements for recognising and measuring revenue arising from contracts with customers (hereinafter IFRS 15) have been adopted starting from January 1, 2018, by recognising, in accordance with the transition requirements of the standard, the cumulative effect of initially applying IFRS 15 as an adjustment to the opening balance of equity as of January 1, 2018, taking into account the contracts existing at that date, without restating the comparative information. In particular, the adoption of IFRS 15 resulted in a decrease in equity of €49 million arising from:

(i) a negative change of €103 million (€259 million before taxes) in the Exploration & Production segment, related to the accounting for amounts of production lifted by a partner within oil-&-gas operations different from its proportionate entitlement (the so-called lifting imbalances), by recognising revenue on the basis of the quantities actually sold (the so-called sales method) instead of the entitled quantities (the so-called entitlement method); costs are recognised on the basis of the quantities actually sold. Moreover the adoption of sales method resulted in the reclassification of underlifting assets (quantities lifted smaller than the entitled ones) and overlifting liabilities (quantities lifted higher than the entitled ones), represented as receivables and payables under the entitlement method, into the other assets and liabilities;

(ii) a positive change of €60 million (€87 million before taxes), related to the capitalisation of the costs of obtaining contracts with customers in the Gas & Power segment, net of their amortisation;

(iii) a negative change of €6 million of equity-accounted investments.

IFRS 9 "Financial Instruments" (hereinafter IFRS 9) has been adopted starting from January 1, 2018. As allowed by the transition requirements of the standard, considering also the complexity of the restatement at the beginning of the first comparative year without the use of hindsight, the impacts of the new classification and measurement requirements, including impairment, of financial assets, have been recognised as an adjustment to the opening balance of equity as of January 1, 2018, without restating the comparative information; with reference to hedge accounting, the adoption of the new requirements did not have significant impacts.

In particular, the adoption of IFRS 9 resulted in an increase in equity of €294 million arising from the fair value measurement of investments in equity instruments previously measured at cost (€681 million), partially offset by the additional impairment losses (€356 million) of trade and other receivables (€427 million before taxes), recognised under the expected credit loss model and by the decrease of the carrying amount of equity-accounted investments (€31 million).

As indicated in the accounting policy for "Investments in equity instruments", Eni elected to designate the investments in equity instruments, held as of January 1, 2018, as assets measured at FVTOCI.

Moreover, with reference to the classification and measurement of financial assets, Eni reclassified the portfolio of financial assets previously classified as available for sale into the financial assets measured at FVTPL (€207 million), on the basis of the facts and circumstances existing as of January 1, 2018.

The breakdown of the abovementioned quantitative effects and reclassifications[24], deriving from the initial application, as of January 1, 2018[25], of IFRS 9 and IFRS 15, is as follows:

(€ million)

Selected line items only	December 31, 2017	Adoption of IFRS 9	Adoption of IFRS 15	Reclassifications	Total effect of the first application	As restated January 1, 2018
Current assets	36,433	*(427)*	*(372)*		(799)	35,634
- *of which: Financial assets held for trading*	*6,012*			*207*	*207*	*6,219*
- *of which: Financial assets available for sale*	*207*			*(207)*	*(207)*	
- *of which: Other current financial assets*	*316*					*316*
- *of which: Trade and other receivables*	*15,421*	*(427)*	*(372)*	*(466)*	*(1,265)*	*14,156*
- *of which: Other current assets*	*1,573*			*466*	*466*	*2,039*
Non-current assets	78,172	*721*	*247*		968	79,140
- *of which: Intangible assets*	*2,925*		*87*		*87*	*3,012*
- *of which: Equity-accounted investments*	*3,511*	*(31)*	*(6)*		*(37)*	*3,474*
- *of which: Other investments*	*219*	*681*			*681*	*900*
- *of which: Deferred tax assets*	*4,078*	*71*	*166*		*237*	*4,315*
Current liabilities	24,735		*(113)*		(113)	24,622
- *of which: Trade and other payables*	*16,748*		*(113)*	*(1,330)*	*(1,443)*	*15,305*
- *of which: Other current liabilities*	*1,515*			*1,330*	*1,330*	*2,845*
Non-current liabilities	42,027		*37*		37	42,064
- *of which: Deferred tax liabilities*	*5,900*		*37*		*37*	*5,937*
Shareholders' equity	48,079	*294*	*(49)*		245	48,324

With reference to year 2018, the application of the previous revenue recognition requirements does not have a significant impact on the Consolidated Financial Statements.

(24) Under IFRS 15, short-term advances from customers have been reclassified from the line item "Trade and other payables" into the line item "Other current liabilities" of the balance sheet in order to present them together with the other current contract liabilities (e.g. customer loyalty programs, deferred income, etc.), already recognised within such line item.

(25) The IFRIC Interpretation 22 "Foreign Currency Transactions and Advance Consideration" is also effective starting from January 1, 2018, but it did not have a significant impact on the Consolidated Financial Statements.

For each kind of financial assets adjusted/reclassified upon the initial application of IFRS 9, the table below provides for the following information: (i) the original measurement category determined in accordance with IAS 39; (ii) the new measurement category determined in accordance with IFRS 9; (iii) the carrying amounts determined in accordance with IAS 39, recognised as of December 31, 2017, and the carrying amounts determined in accordance with IFRS 9 as of January 1, 2018:

(€ million)	Classification under IAS 39	Classification under IFRS 9	Carrying amount under IAS 39	Adjustments	Reclassifications	Other changes(*)	Carrying amount under IFRS 9
Financial assets							
Financial assets held for trading	Held for trading	FVTPL	6,012		207		6,219
Financial assets available for sale	Available-for-sale	FVTPL	207		(207)		
Trade and other receivables(**)	Financing receivables	Amortized cost	15,421	(427)		(838)	14,156
Other investments	Cost	FVTOCI	219	681			900
Total			**21,859**	**254**		**(838)**	**21,275**

(*) Other changes result from the effects related to a different classification under IFRS 15 of receivables for underlifting which have been reclassified as other assets in application of the sales method

(**) Compared to the values presented in the balance sheet at December 31, 2017, the item no longer includes financial receivables, which have been reclassified under the new item "Other current financial assets"

The adoption of the new requirements resulted in some updates of the line items presented in the financial statements; in particular:

- in the profit and loss account: (i) as a consequence of the adoption of IFRS 9, an additional line item to present separately impairment losses/reversals of trade and other receivables (named "Net (impairment losses) reversals of trade and other receivables") was presented; these items were previously recognised within the line item "Purchases, services and other". Consequently, in order to have homogeneous comparative information, these items referred to the comparative years, determined in accordance with the superseded IAS 39, were reclassified into the new line item; and (ii) the line item "Net (impairments) reversals" was renamed as "Net (impairment losses) reversals of tangible and intangible assets";
- in the statement of comprehensive income (loss) an additional line item aimed to present subsequent change of minor investments measured at fair value with effects recognised in OCI, was presented within items that may not be reclassified subsequently to the profit and loss account.

Furthermore, the following changes have been made in the balance sheet:

- the current financing receivables were reclassified out of the line item "Trade and other receivables" into the new line item "Other current financial assets", both in the current and comparative year; this new presentation of the balance sheet was aimed, essentially, to present separately the trade and other exposures from the financial ones, being characterised by different originations, risk profiles and evaluation processes;
- the breakdown of the items of Eni shareholders' equity was updated to present separately the related most relevant items.

4 IFRSs not yet adopted

On January 13, 2016, the IASB issued IFRS 16 "Leases" (hereinafter IFRS 16), which replaces IAS 17 and related interpretations. In particular, IFRS 16 defines a lease as a contract that conveys to the lessee the right to control the use of an identified asset for a period of time in exchange for consideration. The new IFRS eliminates the classification of leases as either operating leases or finance leases for the preparation of lessees' financial statements; in particular, for all leases that have a lease term of more than 12 months, it is required:

- in the balance sheet, to recognise a right-of-use asset, that represents a lessee's right to use an underlying asset (hereinafter also RoU asset), and a lease liability, that represents the lessee's obligation to make the contractual lease payments; as allowed by the standard, the right-of-use assets and the lease liabilities are presented separately from other assets and other liabilities;

- in the profit and loss account, to recognise, within operating costs, the depreciation charges of the right-of-use asset and, within finance expense, the interest expense on the lease liability, if not capitalised, rather than recognising the operating lease payments within the operating expense under IAS 17, effective until year 2018. The depreciation charges of the right-of-use asset and the interest expense on the lease liability directly attributable to the construction of an asset are capitalised as part of the cost of such asset and subsequently recognised in the profit and loss account through depreciation, impairments or write-off, mainly in the case of exploration assets. Moreover the profit and loss account will include: (i) the lease expenses relating to short-term leases or leases of low-value assets, as allowed under the simplified approach provided for by IFRS 16; and (ii) the variable lease payments that are not included in the measurement of the lease liability (e.g., payments based on the use of the underlying asset);
- in the statement of cash flows, to recognise cash payments for the principal portion of the lease liability within the net cash used in financing activities and interest expenses within the net cash provided by operating activities, if they are recognised in the profit and loss account, or within the net cash used in investing activities if they are capitalised as referred to leased assets that are used for the construction of other assets. Consequently, compared with the requirements of IAS 17 no longer not capitalised, but will only include the cash payments for the interest portion of the lease liability, that are not capitalised[26]; (b) an improvement of the net cash used in investing activities, which will no longer include capitalised operating lease payments for property, plant and equipment and intangible assets, but will only include cash payments for the capitalised interest portion of the lease liability and (c) a worsening in the net cash used in financing activities, which will include cash payments for the principal portion of the lease liability.

Conversely, a lessor continues to classify its leases as either operating leases or finance leases. IFRS 16 enhances disclosures both for lessees and for lessors. IFRS 16 shall be applied for annual reporting periods beginning on or after January 1, 2019.

In 2018, the Group completed the analytical activities aimed to identify the areas affected by the adoption of the new requirements, update the processes and systems and assess the expected impacts on the Consolidated Financial Statements.

The adoption of the new requirements affects most of the Group companies; in terms of amounts and/or volumes, the main cases are the following: (i) in the Exploration & Production segment, contracts for the lease of drilling rigs and floating production storage and offloading vessels (the so-called FPSOs); (ii) in the Refining & Marketing and Chemical segment, highway concessions, leases of lands, service stations for the sale of oil products, as well as car fleet dedicated to the car sharing business (Enjoy); (iii) in the Gas & Power segment, leases of vessels used for shipping activities and gas distribution facilities, as well as tolling contracts; (iv) for corporate activities, leases of property.

In the Exploration & Production segment, the activities are often carried out through unincorporated joint operations, managed by one of the partners (the operator), which has the responsibility to carry out the operations and the approved work programmes. The operator usually enters into a contract (including lease contracts), as the sole signatory, for the activities of the unincorporated joint operation. Accordingly, the operator manages the leases, makes lease payments to the lessor and recharges the costs to the other partners (the so-called followers) proportionally. On this regard, the indications of the IFRS Interpretations Committee hereinafter also the (IFRIC) issued in September 2018 applies. In particular, the IFRIC indicated that, in the case of unincorporated joint operations, the operator recognises the entire lease liability, as, by signing the contract, it has primary responsibility for the liability towards the third-party supplier. Therefore if based on the contractual provisions and any other relevant facts and circumstances, Eni has primary responsibility, it shall recognise in the balance sheet: (i) the entire lease liability and (ii) the entire RoU asset, unless there is a sublease with the followers. On the other hand, if the lease contract is signed by all the partners, Eni shall recognise its share of the RoU asset and in the balance sheet based on its working interest. If Eni does not have primary responsibility for the lease liability, it does not recognise any asset or lease liability related to the lease contract. The followers' share of the RoU asset, recognised by the operator, will be recovered according to the joint operation's arrangements by billing the project costs attributable to the followers and collecting the related cash calls. Costs recovered from the followers are recognised as "Other income and revenues" in the profit and loss account and as net cash provided by operating activities in the statement of cash flows. The IFRIC indications have been confirmed at its March 2019 meeting.

(26) The net cash provided by operating activities will include also: (i) the short-term lease payments and payments for leases of low-value assets; and (ii) variable lease payments not included in the measurement of the lease liability.

The complexity of the contracts, as well as their multiannual duration, has required a complex judgement by management to determine the assumptions to be applied in order to estimate the expected impacts deriving from the adoption of the new requirements. In particular, the main assumptions were the following ones:

- for lease contracts related to assets used in the oil-&-gas operations (mainly drilling rigs and FPSOs) set out as operator of the oil-&-gas activities, the recognition of 100% of the lease liability and the right-of-use asset in line with the indications provided by the IFRIC. When the lease contracts are set out by companies, other than subsidiaries, that act as operators on behalf of the other participating companies (the so-called operating companies), consistently with the provision to recover from the followers the costs related to the oil-&-gas activities, the participating companies recognise their shares of the right-of-use assets and the lease liabilities based on their working interest, considering any available information on the expected use of the underlying assets;
- the separation of non-lease components, also on the basis of in-depth analyses performed with external experts, with reference to the main contracts related to the upstream activities (drilling rigs) which provide for single payments relating to both lease and non-lease components;
- the assessment of extension or termination options in order to determine the lease term;
- the identification of variable lease payments and their characteristics in order to establish whether or not[27] they shall be included in the measurement of the lease liability and the right-of-use asset;
- the discount rate used to measure the lease liability that is the lessee's incremental borrowing rate. This rate have been defined considering the lease term of the lease contracts, the currencies and the characteristics of the lessees' economic environment, defined on the basis of the country risk premium assigned to each country where Eni operates.

On initial application, Eni elects to apply the following practical expedients allowed by the accounting standard:

- possibility to adopt the modified retrospective approach, by recognising the cumulative effect of initially applying the new standard as an adjustment to the opening balance at January 1, 2019, without restating the comparative information;
- possibility not to reassess each contract existing at January 1, 2019, by applying IFRS 16 to all contracts previously identified as leases (under IAS 17 and IFRIC 4), while not applying IFRS 16 the to contracts that were not previously identified as leases;
- for contracts previously classified as operating leases, possibility to measure the right-of-use asset at an amount equal to the lease liability, adjusted, if necessary, by any prepaid amounts already recognised in the balance sheet;
- as an alternative to performing an impairment review, possibility to adjust the right-of-use assets, existing at January 1, 2019, by the amount of any provision for onerous lease contracts recognised at December 31, 2018;
- upon transition, election not to consider leases for which the lease term ends within 12 months of January 1, 2019 as short-term leases.

Based on the available information, the adoption of IFRS 16 results in the recognition of right-of-use assets for €5.7 billion and lease liabilities for €5.8 billion; the estimated amount of the lease liabilities includes the payables for lease fees outstanding at January 1, 2019, previously classified as trade payables. The estimated impacts of the initial adoption of IFRS 16 might be subject to change due to any evolution in the interpretations deriving, among others, from further IFRIC indications, as well as due to the development of the data process upon initial adoption of the standard in the 2019 financial reports. Moreover, the estimated amount of the lease liabilities includes the share of the lease liabilities corresponding to the followers' working interest for €2.0 billion, while the Eni working interest for €3.8 billion.

(27) Under IFRS 16, variable lease payments linked to future sales or use of an underlying asset are recognised in the profit and loss account and so they are not included in the measurement of the lease liability/right-of-use asset.

Based on of the currently available information, a reconciliation between the amount of future minimum lease payments under non-cancellable operating leases at December 31, 2018 and the opening balance of the lease liability at January 1, 2019 is provided below:

(€ billion)

Future minimum lease payments under non-cancellable operating leases at December 31, 2018	**4.0**
- Recognition of the shares of leases related to followers	2.0
- Effect of discounting	(1.5)
- Extension options	1.2
- Other changes	0.1
Lease liability at January 1, 2019	**5.8**

On May 18, 2017, the IASB issued IFRS 17 "Insurance Contracts" (hereinafter IFRS 17), which sets out the accounting for the insurance contracts issued and the reinsurance contracts held. IFRS 17, which replaces IFRS 4 "Insurance Contracts", shall be applied for annual reporting periods beginning on or after January 1, 2021.

On June 7, 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments" (hereinafter IFRIC 23), which clarifies the accounting for (current and/or deferred) tax assets and liabilities when there is uncertainty over income tax treatments. IFRIC 23 shall be applied for annual reporting periods beginning on or after January 1, 2019.

On October 12, 2017, the IASB issued the amendments to IAS 28 "Long-term Interests in Associates and Joint Ventures" (hereinafter the amendments to IAS 28), which clarify that entities account for long-term interests in an associate or joint venture, that, in substance, form part of the entity's net investment in the investee and for which settlement is neither planned nor likely to occur in the foreseeable future, using the provisions of IFRS 9, including those related to impairment. The amendments to IAS 28 shall be applied for annual reporting periods beginning on or after January 1, 2019.

On February 7, 2018, the IASB issued the amendments to IAS 19 "Plan Amendment, Curtailment or Settlement" (hereinafter the amendments to IAS 19), which require to use updated actuarial assumptions to determine current service cost and net interest, when an amendment, curtailment or settlement to an existing defined benefit pension plan takes place, for the remainder reporting period after the change of the plan. The amendments to IAS 19 shall be applied for annual reporting periods beginning on or after January 1, 2019.

On March 29, 2018, the IASB issued the document "Amendments to References to the Conceptual Framework in IFRS Standards", which includes, basically, technical and editorial changes to existing IFRS standards in order to update references in those standards to previous versions of the IFRS Framework with the new Conceptual Framework for Financial Reporting, issued by the IASB on the same date. The amendments to the standards shall be applied for annual reporting periods beginning on or after January 1, 2020.

On October 22, 2018, the IASB issued the amendments to IFRS 3 "Business Combinations" (hereinafter the amendments to IFRS 3), which clarify the definition of a business. The amendments to IFRS 3 shall be applied for annual reporting periods beginning on or after January 1, 2020.

On October 31, 2018, the IASB issued the amendments to IAS 1 and IAS 8 "Definition of Material" (hereinafter the amendments to IAS 1 and IAS 8), which clarify, and align across all IFRS Standards and other publications, the definition of material to help companies make better materiality judgements. In particular, information is material if omitting, misstating or obscuring it could be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements. The amendments to IAS 1 and IAS 8 shall be applied for annual reporting periods beginning on or after January 1, 2020.

On December 12, 2017, the IASB issued the document "Annual Improvements to IFRS Standards 2015-2017 Cycle", which includes, basically, technical and editorial changes to existing standards. The amendments to the standards shall be applied for annual reporting periods beginning on or after January 1, 2019.

Eni is currently reviewing the IFRSs not yet adopted in order to determine the likely impact on the Consolidated Financial Statements.

5 Cash and cash equivalents

Cash and cash equivalents of €10,836 million (€7,363 million at December 31, 2017) included financial assets with maturity generally of up to three months at the date of inception amounting to €8,732 million (€5,591 million at December 31, 2017) and mainly included short-term deposits with financial institutions having notice of more than 48 hours.

Cash and cash equivalents consist essentially of bank deposits in euro and U.S. dollars as a way to employ the Group cash on hand with a view of funding the Group's short-term financing needs.

The average maturity of bank deposits in euro of €7,653 million was 29 days and the interest rate was a negative 0.29%; the average maturity of bank deposits in U.S. dollars of €1,074 million was 12 days with an internal rate of return of 2.59%.

6 Financial assets held for trading

(€ million)	December 31, 2018	December 31, 2017
Quoted bonds issued by sovereign states	1,083	1,022
Other	5,469	4,990
	6,552	**6,012**

From January 1, 2018, financial assets held by the Group captive insurance company Insurance DAC of €207 million, previously classified as available for sale, have been classified as held for trading in accordance to the provisions of IFRS 9 on the base of the conditions existing at the adoption date.

The Company has established a liquidity reserve as part of its internal targets and financial strategy with a view of ensuring an adequate level of flexibility to the Group development plans and of coping with unexpected fund requirements or difficulties in accessing financial markets. The management of this liquidity reserve is performed through trading activities in view of the financial optimization of returns, within a predefined and authorized level of risk tolerance, targeting the preservation of the invested capital and the ability to promptly convert it into cash.

Financial assets held for trading of Eni SpA include securities subject to lending agreements of €1,301 million (€845 million at December 31, 2017).

The breakdown by currency is provided below:

(€ million)	December 31, 2018	December 31, 2017
Euro	4,573	4,232
U.S. dollars	1,614	1,025
Other currencies	365	755
	6,552	**6,012**

The breakdown by issuing entity and credit rating is presented below:

	Nominal value (€ million)	Fair Value (€ million)	Rating – Moody's	Rating – S&P
Quoted bonds issued by sovereign states				
Fixed rate bonds				
Italy	523	529	Baa3	BBB
Other(*)	336	349	from Aaa to Baa3	from AAA to BBB-
	859	**878**		
Floating rate bonds				
Italy	130	129	Baa3	BBB
Other(*)	86	76	from Aaa to Baa3	from AAA to BBB-
	216	**205**		
Total quoted bonds issued by sovereign states	**1,075**	**1,083**		
Other Bonds				
Fixed rate bonds				
Quoted bonds issued by industrial companies	1,628	1,581	from Aa2 to Baa3	from AA to BBB-
Quoted bonds issued by financial and insurance companies	1,270	1,269	from Aaa to Baa3	from AAA to BBB-
Other	51	48	from A1 to Baa3	from A+ to BBB-
	2,949	**2,898**		
Floating rate bonds				
Quoted bonds issued by financial and insurance companies	1,562	1,453	from Aaa to Baa3	from AAA to BBB-
Quoted bonds issued by industrial companies	987	976	from Aa2 to Baa2	from AA to BBB
Other	158	142	from Aa3 to Baa3	from AA- to BBB-
	2,707	**2,571**		
Total other bonds	**5,656**	**5,469**		
Total other financial assets held for trading	**6,731**	**6,552**		

(*) Individual amounts included herein are lower than €50 million.

The fair value hierarchy is level 1 for €6,362 million and level 2 for €190 million. During 2018, there were no transfers between the different hierarchy levels of fair value.

7 Trade and other receivables

As of January 1, 2018, the effects of the application of IFRS 9 and IFRS 15 are the following:

(€ million)	Trade and other receivables
Amount as of 31 December 2017	**15,421**
Changes in accounting policies (IFRS 9)	(427)
Changes in accounting policies (IFRS 15)	(372)
Reclassification to other current asssets (IFRS 15)	(466)
Amount as of 1 January 2018	**14,156**

The adoption of IFRS 9 determined an increase in the provision for doubtful accounts of €427 million in application of the expected loss model.

The application of IFRS 15 determined a decrease in other receivables for €372 million due to the fact that Eni now adopts the sales method versus the entitlement method previously adopted under the previous accounting policy as disclosed in note 3 – Changes in accounting policies.

In applying IFRS 15, €466 million of assets related to lifting imbalances accounted for using the sales method have been reclassified to other current assets.

More information about the application of IFRS 9 and IFRS 15 is disclosed in note 3 — Changes in accounting policies.

The following is the analysis of trade and other receivables:

(€ million)	December 31, 2018	December 31, 2017
Trade receivables	9,520	10,182
Receivables from divestments	122	597
Receivables from operators in E&P activities	3,024	3,369
Other receivables	1,435	1,273
	14,101	**15,421**

Generally, trade receivables do not bear interest and provide payment terms within 180 days.

Trade receivables decreased by €662 million, of which €641 million related to the Gas & Power segment.

At December 31, 2018, Eni sold without recourse trade receivables due in 2019 for €1,769 million (€2,051 million at December 31, 2017 due in 2018). Derecognized receivables related to the Gas & Power segment for €1,419 million and to the Refining & Marketing and Chemical segment for €350 million.

Receivables from divestments decreased by €475 million due to: (i) the collection of the price installments related the sale of 10% and 30% interests in the Zohr asset in Egypt made in 2017 respectively to BP and Rosneft for a total amount of €433 million. An additional installment relating to the transaction with BP will be collected in June 2019 (€119 million); (ii) the collection for €153 million of the third and last instalment of a receivable on the divestment of a 1.71% interest in the Kashagan project to the local partner KazMunayGas.

Amounts receivable from operators in exploration and production projects included amounts owed by partners in Nigeria for €977 million (€1,507 million at December 31, 2017). This latter comprised an amount of €681 million in large part overdue (€713 million at December 31, 2017) owed by the Nigerian national oil company NNPC in respect of the contractual recovery of the expenditures incurred at certain projects operated by Eni. During the year, the Company recovered €140 million of the overdue amount due to the implementation of the "Repayment Agreement" agreed with the counterparty, whereby Eni is to be reimbursed through the sale of the profit oil attributable to NNPC in certain rig-less petroleum initiatives with low mineral risk. Based on Eni's Brent price scenario, the reimbursement will be accomplished over a time horizon of three to five years. The overdue receivables are stated net of a discount factor. In addition, a receivable relating to the recovery of a disputed amount of expenditures due to the same counterpart was completely written down (€153 million at December 31, 2017).

Receivables from others comprised the recoverable value amounting to €300 million of certain overdue trade receivables towards the state-owned oil company of Venezuela, PDVSA, in relation to gas equity volumes supplied by the joint venture Cardón IV, equally participated by Eni and Repsol. The two shareholders purchased those receivables from the venture in 2016 and in 2018. The proceeds from the sale were utilized to reimburse part of the financing loan provided by the same shareholders to fund the development of the gas project reserves. The recoverable amount of those receivables was estimated considering the lifetime expected credit losses which were evaluated based on a financial model built around empirical evidence and outcomes from a thorough review of sovereign defaults. Risks associated with the complex financial outlook of the Country and the deteriorated operating environment were appreciated in the recoverability estimation by assuming a deferral in the timing of collection of future revenues and overdue credit amounts.

Trade and other receivables stated in euro and US dollars amounted to €7,100 million and €6,119 million, respectively.

Credit risk exposure and expected losses relating to trade and other receivables has been prepared on the basis of internal ratings as follows:

	Performing receivables					
(€ million)	Low risk	Medium Risk	High Risk	Defaulted receivables	Eni gas e luce customers	Total
December 31, 2018						
Business customers	2,454	3,585	1,152	1,350		8,541
National Oil Companies and public administrations	1,292	157	672	2,217		4,338
Other counterparties	1,494	77	156	271	2,374	4,372
Gross amount	**5,240**	**3,819**	**1,980**	**3,838**	**2,374**	**17,251**
Allowance for doubtful accounts	(9)	(3)	(44)	(2,237)	(857)	(3,150)
Net amount	**5,231**	**3,816**	**1,936**	**1,601**	**1,517**	**14,101**
Expected loss (% net of counterpart risk mitigation factors)	0.2	0.1	2.6	62.5	36.1	

Eni has classified its business customers and the associated commercial or industrial exposures based on an individual assessment of the credit and the counterparty risks. Business customers other than National Oil Companies (NOC) and public administrations, each of whom has undergone an individual credit evaluation, have assigned a probability of default calculated based on internal ratings which factor in: (i) a full assessment of each customer profitability, financial condition and liquidity and business a financial prospects on an ongoing basis; (ii) history of the contractual relationship (timeliness in invoice payment, number of claims, etc.); (iii) presence of mitigation factors of credit risk (e.g. securitization package, insurance against the credit risk, guarantee from third parties, etc.); (iv) other specialized pieces of information obtained by the Company's business commercial function or by specialized info-providers; (v) industrial and market trends. Internal ratings and the probability of default are constantly updated by means of back-testing analysis and risk assessment of the current credit portfolio. The loss given default associated with those industrial customers is estimated by the business based on the past experience in credit recoverability; in the case of defaulting customers, loss given default is estimated based on the recovery rates obtained in situations of credit restructurings or litigation procedures.

The probability of default associated with NOCs and public administrations is estimated based on the country risk premium incorporated in the risk-adjusted weighted average cost of capital utilized by the Company to perform the impairment review of its fixed assets. The loss given default of these business partners is estimated based on historical averages of delays in collecting overdue receivables, substantially assessing the time value of money. The resulting loss given default is adjusted to factor in any existing mitigation factor. In case of particular market conditions or sovereign defaults, the expected loss associated with NOCs is re-rated based on the empirical evidence and outcomes obtained from restructuring of sovereign debts considering the specificities of trading relationships with energy companies.

Customers of Eni gas e luce have been grouped into homogeneous clusters with different credit risk and probability of default which have been estimated based on past experience on credit collection, systematically updated and, in case of particular market conditions, adjusted to take into account expected market and credit trends in any given cluster.

The exposure to credit risk and expected losses relating to customers of Eni gas e luce was assessed on the basis of a provision matrix as follows:

	Ageing					
(€ million)	Not-past due	from 0 to 3 months	from 3 to 6 months	from 6 to 12 months	over 12 months	Total
December 31, 2018						
Customers – Eni gas e luce:						
- Retail	575	49	34	64	554	1,276
- Middle	449	43	13	29	349	883
- Other	207	2	1	2	3	215
Gross amount	**1,231**	**94**	**48**	**95**	**906**	**2,374**
Allowance for doubtful accounts	(20)	(18)	(18)	(56)	(745)	**(857)**
Net amount	**1,211**	**76**	**30**	**39**	**161**	**1,517**
Expected loss (%)	1.6	19.1	37.5	58.9	82.2	36.1

Trade and other receivables are stated net of the valuation allowance for doubtful accounts which has been determined considering the counterparty risk mitigation factors amounting to €3,072 million:

(€ million)	Trade and other receivables
Carrying amount at December 31, 2017	**2,639**
Changes in accounting policies (IFRS 9)	427
Carrying amount at January 1, 2018	**3,066**
Additions on trade and other performing receivables	126
Additions on trade and other defaulted receivables	372
Deductions on trade and other performing receivables	(189)
Deductions on trade and other defaulted receivables	(532)
Other changes	307
Carrying amount at December 31, 2018	**3,150**
Carrying amount at December 31, 2016	**2,303**
Additions	927
Deductions	(454)
Other changes	(137)
Carrying amount at December 31, 2017	**2,639**

Additions to allowance for doubtful accounts on trade and other performing receivables related for €108 million to the Gas & Power segment, particularly in the retail business.

Additions to allowance for doubtful accounts on trade and other defaulted receivables related for €291 million to the Exploration & Production segment and in connection with receivables for the supply of equity hydrocarbons to State-owned companies and other commercial partners.

Utilizations of allowance for doubtful accounts on trade and other performing and defaulted receivables amounted to €721 million and mainly related to the Gas & Power segment for €613 million, in particular utilizations against charges of €579 million mainly in the retail business. The mitigation measures regarding the counterparty risk executed by the Company, including better customer selection, allowed to reduce the incidence of unpaid amounts on retail sales of gas and power to physiological levels.

Net (impairment losses) reversals of trade and other receivables are disclosed as follows:

(€ million)	2018
Net (impairment losses) reversals of trade and other receivables	
New or increased provisions	(498)
Credit losses	(37)
Reversal of unutilized provisions	120
	(415)

With reference the receivables for the year 2017 stated according to the valuation criteria in force before the application of IFRS 9 “Financial instruments”, the analysis of the 2017 ageing of trade and other receivables was as follows:

	December 31, 2017	
(€ million)	Trade receivables	Other receivables
Neither impaired nor past due	**8,800**	**4,604**
Impaired (net of the valuation for doubtful accounts)	**567**	**31**
Not impaired and past due:		
- within 90 days	478	21
- from 3 to 6 months	46	9
- from 6 to 12 months	147	202
- over 12 months	144	372
	815	**604**
	10,182	**5,239**

Because of the short-term maturity and conditions of remuneration of trade and other receivables, the fair value approximated the carrying amount.

Receivables with related parties are disclosed in note 36 — Transactions with related parties.

8 Non-current and current inventories

(€ million)	December 31, 2018	December 31, 2017
Raw and auxiliary materials and consumables	889	999
Materials and supplies	1,451	1,566
Finished products and goods	2,274	2,000
Certificates and emission rights	37	56
	4,651	**4,621**

Raw and auxiliary materials and consumables include oil-based feedstock, catalysts and other consumables pertaining to refining and chemical activities.

Materials and supplies include materials to be consumed in drilling activities and spare parts related to the Exploration & Production segment for €1,334 million (€1,441 million at December 31, 2017).

Finished products and goods included gas and petroleum products for €1,543 million (€1,287 million at December 31, 2017) and chemical products for €547 million (€489 million at December 31, 2017).

Certificates and emission rights are measured at the fair value. The fair value hierarchy is level 1.

Inventories of €95 million (€86 million at December 31, 2017) were pledged to guarantee the estimated imbalance in volumes input to/off-taken from the national gas network operated by Snam Rete Gas SpA.

Inventories are stated net of a write down provision of €578 million (€245 million at December 31, 2017). Net additions to write down provision for 2018 amounted to €337 million and primarily related to the alignment of the carrying amount of crude oil and oil products inventories to their net realizable values at the period end, as a consequence of the rapid decline in hydrocarbons prices recorded in the final months of 2018.

Inventories held for compliance purposes of €1,217 million (€1,283 million at December 31, 2017) primarily related to Italian subsidiaries for €1,200 million (€1,267 million at December 31, 2017) in accordance with minimum stock requirements for oil and petroleum products set forth by applicable laws.

9 Current income tax receivables and payables

(€ million)	December 31, 2018 Receivables	December 31, 2018 Payables	December 31, 2017 Receivables	December 31, 2017 Payables
Income taxes	191	440	191	472
Other taxes and duties	561	1,432	729	1,472
	752	**1,872**	**920**	**1,944**

Income taxes are described in note 32 — Income tax expense.

Receivables for other taxes and duties included VAT credits for €383 million (€452 million at December 31, 2017) in relation to down payments by Italian subsidiaries made in December.

Payables for other taxes and duties consisted of excise and custom duties of €636 million (€824 million at December 31, 2017).

10 Other assets

(€ million)	December 31, 2018 Current	December 31, 2018 Non-current	December 31, 2017 Current	December 31, 2017 Non-current
Fair value of derivative financial instruments	1,594	68	1,231	80
Other current assets	664	724	342	1,243
	2,258	**792**	**1,573**	**1,323**

The fair value related to derivative financial instruments is disclosed in note 23 — Derivative financial instruments and hedge accounting.

The increase in other assets of €322 million included the reclassification as of January 1, 2018, from the item Trade and other receivables of the underlifting imbalances related to the Exploration & Production segment for €466 million following the adoption of the sales method in application of IFRS 15.

Other assets include: (i) non-current tax assets for € 422 million (€ 507 million at December 31, 2017); (ii) gas volumes prepayments that were made in previous years due to the take-or-pay obligations in relation to the Company's long-term supply contracts of €26 million (€119 million at 31 December 2017); (iii) non-current receivables from others for €35 million (€44 million at December 31, 2017); (iv) non-current receivables for investing activities for €9 million (€118 million at December 31, 2017).

Transactions with related parties are described in note 36 — Transactions with related parties.

11 Property, plant and equipment

(€ million)	Land and buildings	E&P wells, plant and machinery	Other plant and machinery	E&P exploration assets and appraisal	E&P tangible assets in progress	Other tangible assets in progress and advances	Total
2018							
Net carrying amount – beginning of the year	**1,313**	**45,782**	**3,877**	**1,371**	**9,469**	**1,346**	**63,158**
Additions	18	432	173	330	6,947	878	**8,778**
Depreciation	(65)	(6,012)	(529)				**(6,606)**
Reversals	41	299	86				**426**
Impairments	(61)	(477)	(73)		(548)	(117)	**(1,276)**
Write-off		(12)	(1)	(66)	(4)	(1)	**(84)**
Disposals	(2)	(400)	(9)	(32)	(198)	2	**(639)**
Currency translation differences	2	1,623	36	53	385	(1)	**2,098**
Decrease through loss of control of subsidiary	1	(4,388)	32	(58)	(474)	10	**(4,877)**
Transfers	81	6,795	461	(294)	(6,501)	(542)	
Other changes	(54)	(786)	(152)	(37)	119	234	**(676)**
Net carrying amount – end of the year	**1,274**	**42,856**	**3,901**	**1,267**	**9,195**	**1,809**	**60,302**
Gross carrying amount – end of the year	**4,060**	**135,467**	**27,516**	**1,267**	**12,559**	**2,415**	**183,284**
Provisions for depreciation and impairments	**2,786**	**92,611**	**23,615**		**3,364**	**606**	**122,982**
2017							
Net carrying amount – beginning of the year	**1,258**	**47,090**	**3,789**	**1,905**	**15,135**	**1,616**	**70,793**
Additions	22	42	190	351	7,302	583	**8,490**
Depreciation	(71)	(6,583)	(545)				**(7,199)**
Reversals	5	608	273		169		**1,055**
Impairments	(2)	(491)	(83)		(146)	(126)	**(848)**
Write-off		(3)	(2)	(232)	(2)		**(239)**
Disposals	(15)	3	(6)		(1,376)	(54)	**(1,448)**
Currency translation differences	(5)	(5,155)	(143)	(193)	(1,527)	(2)	**(7,025)**
Transfers	84	9,940	629	(265)	(9,673)	(715)	
Other changes	37	331	(225)	(195)	(413)	44	**(421)**
Net carrying amount – end of the year	**1,313**	**45,782**	**3,877**	**1,371**	**9,469**	**1,346**	**63,158**
Gross carrying amount – end of the year	**4,061**	**137,223**	**26,746**	**1,371**	**12,315**	**2,061**	**183,777**
Provisions for depreciation and impairments	**2,748**	**91,441**	**22,869**		**2,846**	**715**	**120,619**

Capital expenditures included capitalized finance expenses of €52 million (€72 million in 2017) related to the Exploration & Production segment (€37 million). The interest rate used for capitalizing finance expense ranged from 2.3% to 2.4% (1.6% to 2.7% at December 31, 2017).

Capital expenditures primarily related to the Exploration & Production segment for €7,757 million (€7,638 million in 2017) and included the consideration paid for the award of the interests in the already producing Concession Agreements of Umm Shaif and Nasr (10%) and Lower Zakum (5%) and the Concession Agreement of Gasha (25%) under development, located in the offshore of Abu Dhabi (United Arab Emirates). The price paid of €869 million was allocated to proved mineral interest (E&P wells, plant and machinery) for €382 million and to unproved mineral interest (E&P tangible assets in progress) for €487 million.

More information is reported in note 35 — Segment information and information by geographical area.

The main depreciation rates used were substantially unchanged from the previous year and ranged as follows:

(%)	
Buildings	2 – 10
Mineral exploration wells and plants	UOP
Refining and chemical plants	2 – 17
Gas pipelines and compression stations	2 – 12
Power plants	5
Other plant and machinery	6 – 12
Industrial and commercial equipment	5 – 25
Other assets	10 – 20

The criteria adopted by Eni for determining net (impairments) reversals is reported in note 13 — Net reversal (impairment) of tangible and intangible assets.

Disposals related to a 10% interest in the Zohr asset in Egypt to Mubadala Petroleum Llc with a gain of €418 million.

Foreign currency translation differences primarily related to subsidiaries which utilize the U.S. dollar as functional currency (€2,209 million).

Property, plant and equipment decreased by €4,800 million due to the exclusion from the consolidation of the assets of the former Eni's subsidiary Eni Norge AS which was merged with Point Resources AS, fully-owned by HitecVision AS, to establish the equity-accounted joint venture Vår Energi AS, jointly controlled by Eni (69.60%) and HitecVision AS with the initial recognition among equity-accounted investments of Eni's interest in the combined entity.

Transfers from E&P tangible assets in progress to E&P wells, plant and machinery related for €2,750 million to progress in the development of reserves at large projects, comprising Zohr, Jangkrik, East Hub, Noroos and OCTP projects.

Changes in exploration and appraisal activities related to: (i) the successful completion of exploration and appraisal activities at certain suspended exploration wells and their transfer to tangible assets for €297 million; (ii) the write-off of exploration wells for €66 million due to the negative outcome of exploration and appraisal activities, mainly relating to two offshore projects in Morocco and Vietnam.

Other changes of included a downward revision of estimates of the decommissioning provision of the Exploration & Production segment (negative €503 million) due to increased discount rates curve, especially for the U.S. dollar.

Exploration and appraisal activities related for €1,101 million to costs of suspended exploration wells pending final determination and for €166 million to costs of exploration wells in progress at the end of the year. Changes relating to suspended wells are showed:

(€ million)	2018	2017	2016
Costs for exploratory wells suspended – beginning of the period	**1,263**	**1,684**	**1,737**
Increases for which is ongoing the determination of proved reserves	235	451	282
Amounts previously capitalized and expensed in the period	(61)	(217)	(109)
Reclassification to successful exploratory wells following the estimation of proved reserves	(297)	(278)	(276)
Disposals	(6)	(199)	
Decrease through loss of control of subsidiary	(58)		
Reclassification to assets held for sale	(24)		
Currency translation differences	49	(178)	50
Costs for exploratory wells suspended – end of the period	**1,101**	**1,263**	**1,684**

The following information relates to the stratification of the suspended wells pending final determination (ageing):

	2018		**2017**		**2016**	
	(€ million)	**(number of wells in Eni's interest)**	**(€ million)**	**(number of wells in Eni's interest)**	**(€ million)**	**(number of wells in Eni's interest)**
Costs capitalized and suspended for exploratory well activity						
- within 1 year	111	7.02	222	7.95	16	1.05
- between 1 and 3 years	87	2.88	241	3.87	609	10.25
- beyond 3 years	903	24.20	800	21.44	1,059	21.55
	1,101	**34.10**	**1,263**	**33.26**	**1,684**	**32.85**
Costs capitalized for suspended wells						
- fields including wells drilled over the last 12 months	111	7.02	148	5.88	9	0.55
- fields for which the delineation campaign is in progress	217	4.66	261	4.69	251	3.51
- fields including commercial discoveries that proceeds to sanctioning	773	22.42	854	22.69	1,424	28.79
	1,101	**34.10**	**1,263**	**33.26**	**1,684**	**32.85**

Unproved mineral interests include the purchase price allocated to unproved reserves following business combinations or acquisition of individual properties. Unproved mineral interests were as follows:

(€ million)	Congo	Nigeria	Turkmenistan	USA	Algeria	Egypt	United Arab Emirates	Total
2018								
Book amount at the beginning of the year	**1,162**	**825**	**192**	**99**	**105**	**7**		**2,390**
Additions	26	56				23	487	592
Net (impairments) reversals	(429)		(76)					(505)
Reclassification to proved mineral interest	(32)		(44)		(32)	(2)		(110)
Other changes and currency translation differences	42	40	5	4	4	1	15	111
Book amount at the end of the year	**769**	**921**	**77**	**103**	**77**	**29**	**502**	**2,478**
2017								
Book amount at the beginning of the year	**1,254**	**938**	**138**	**113**		**7**		**2,450**
Additions					112			112
Net (impairments) reversals	72		75					147
Reclassification to proved mineral interest	(7)							(7)
Other changes and currency translation differences	(157)	(113)	(21)	(14)	(7)			(312)
Book amount at the end of the year	**1,162**	**825**	**192**	**99**	**105**	**7**		**2,390**

Unproved mineral interest comprised a property denominated Oil Prospecting License 245 ("OPL 245"), located in the offshore of Nigeria, with a net book value of €857 million, which corresponded to the price paid to the Nigerian Government to acquire a 50% interest in the property, with the partner Shell acquiring the remaining 50%. As of December 31, 2018, the net book value of the property was €1,159 million, including capitalized exploration costs and pre-development costs. The acquisition of OPL 245 is subject to judicial proceedings in Italy and in Nigeria for alleged corruption and money laundering in respect of the Resolution Agreement signed on April 29, 2011, relating to the purchase of the license by Eni and Shell. Those proceedings are disclosed in note 27 — Guarantees, Commitments and Risks.

Additions for the year related to the acquisition of unproved reserves as part of the deals to acquire interests in oil&gas assets in production/development phase in the offshore of Abu Dhabi (United Arab Emirates), the extension of the concession terms in Nigeria and Egypt and contractual revisions in Congo.

Accumulated provisions for impairments amounted to €16,471 million (€16,005 million at December 31, 2017).

At December 31, 2018, Eni pledged property, plant and equipment for €24 million primarily as collateral against certain borrowings (same amount as of December 31, 2017).

Government grants recorded as a decrease of property, plant and equipment amounted to €125 million (€110 million at December 31, 2017).

Assets acquired under financial lease agreements amounted to €46 million (€29 million at December 31, 2017).

Contractual commitments related to the purchase of property, plant and equipment are disclosed in note 27 — Guarantees, commitments and risks — Liquidity risk.

Property, plant and equipment under concession arrangements are described in note 27 — Guarantees, commitments and risks — Assets under concession arrangements.

12 Intangible assets

(€ million)	Exploration rights	Industrial patents and intellectual property rights	Other intangible assets	Intangible assets with finite useful lives	Goodwill	Total
2018						
Net carrying amount – beginning of the year	**995**	**240**	**486**	**1,721**	**1,204**	**2,925**
Changes in accounting policies (IFRS 9 and 15)			87	**87**		**87**
Net carrying amount restated – beginning of the year	**995**	**240**	**573**	**1,808**	**1,204**	**3,012**
Additions	133	28	180	**341**		**341**
Amortization	(71)	(87)	(226)	**(384)**		**(384)**
Impairments			(16)	**(16)**		**(16)**
Write-off	(15)		(1)	**(16)**		**(16)**
Currency translation differences	39			**39**	8	**47**
Change through loss of control of subsidiary			74	**74**	46	**120**
Other changes		40		**40**	26	**66**
Net carrying amount at the end of the year	**1,081**	**221**	**584**	**1,886**	**1,284**	**3,170**
Gross carrying amount at the end of the year	**1,686**	**1,534**	**4,188**	**7,408**		
Provisions for amortization and impairment	**605**	**1,313**	**3,604**	**5,522**		
2017						
Net carrying amount – beginning of the year	**1,092**	**259**	**598**	**1,949**	**1,320**	**3,269**
Additions	91	17	83	**191**		**191**
Amortization	(65)	(84)	(137)	**(286)**		**(286)**
Reversals	32			**32**		**32**
Impairments	(14)			**(14)**		**(14)**
Write-off	(24)			**(24)**		**(24)**
Currency translation differences	(115)	(1)	(2)	**(118)**	(23)	**(141)**
Other changes	(2)	49	(56)	**(9)**	(93)	**(102)**
Net carrying amount – end of the year	**995**	**240**	**486**	**1,721**	**1,204**	**2,925**
Gross carrying amount – end of the year	**1,504**	**1,466**	**3,778**	**6,748**		
Provisions for amortization and impairment	**509**	**1,226**	**3,292**	**5,027**		

Exploration rights comprised the residual book value of license and leasehold property acquisition costs relating to areas with proved reserves, which are amortized based on UOP criteria and are regularly reviewed for impairment. Furthermore, they include the cost of unproved areas which are suspended pending a final determination of the success of the exploratory activity or until management confirms its commitment to the initiative. Additions for the year related to signature bonuses paid for the acquisition of new exploration acreage in United Arab Emirates, United States and Mexico.

The breakdown of exploration rights by type of asset was as follows:

(€ million)	December 31, 2018	December 31, 2017
Proved licence and leasehold property acquisition costs	357	403
Unproved licence and leasehold property acquisition costs	684	586
Other mineral interests	40	6
	1,081	**995**

Industrial patents and intellectual property rights mainly regarded the acquisition and internal development of software and rights for the use of production processes and software.

Other intangible assets comprised: (i) customer acquisition costs relating to the retail gas business for €166 million; (ii) concessions, licenses, trademarks and similar items for €151 million comprised transmission rights for natural gas imported from Algeria of €27 million; (iii) capital expenditures in progress on natural gas pipelines for which Eni has acquired transport rights for €78 million (same amount as of December 31, 2017).

The main amortization rates used were substantially unchanged from the previous year and ranged as follows:

(%)	
Exploration rights	UOP – 33
Transport rights of natural gas	3
Other concessions, licenses, trademarks and similar items	3 – 33
Service concession arrangements	20 – 33
Capitalized costs for customer acquisition	25 – 33
Other intangible assets	4 – 20

The carrying amount of goodwill at the end of the year amounted €2,422 million, net of cumulative impairments charges.

A breakdown of the stated goodwill by operating segment is provided below:

(€ million)	December 31, 2018	December 31, 2017
Gas & Power	977	932
Exploration & Production	187	179
Refining & Marketing	119	93
Other activities	1	
	1,284	**1,204**

Goodwill acquired through business combinations has been allocated to the CGUs that are expected to benefit from the synergies of the acquisition.

The amount of goodwill outstanding at the reporting date mainly related to the Gas & Power segment. A breakdown is disclosed below.

(€ million)	December 31, 2018	December 31, 2017
Domestic gas market	835	835
European gas market	142	97
	977	**932**

Goodwill allocated to the CGU domestic gas market was recognized upon the buy-out of the former Italgas SpA minorities in 2003 through a public offering (€706 million). The acquired entity engaged in the retail sale of gas to the residential sector and middle and small-sized businesses in Italy. In addition, further goodwill amounts have been allocated over the years following business combinations with small, local companies selling gas to residential customers in focused territorial reach and municipalities synergic to Eni's activities. The impairment review performed at the balance sheet date confirmed the recoverability of the carrying amount of this CGU including any allocated goodwill.

In assessing the recoverability of the carrying amount of the CGU domestic gas market, including the allocated portion of goodwill, management determined the value in use of the CGU considering the sales margin exclusively of the retail market (excluding margins on sales to wholesalers, industrial and power generation customers). The assessment was performed considering the cash flows of the four-year plan approved by management and incorporating the perpetuity of the last year of the plan to determine the terminal value by assuming a nominal long-term growth rate equal to zero, unchanged from the previous reporting period. These cash flows were discounted by using the post-tax WACC adjusted considering the specific country risk of 5.4% for Italy. Post-tax cash flows and discount rates were adopted as they resulted in an assessment that substantially approximated a pre-tax assessment.

The excess of the recoverable amount of the CGU Domestic gas market over its carrying amount including the allocated portion of goodwill (headroom) amounting to €1,701 million would be reduced to zero under each of the following alternative hypothesis: (i) a decrease of 63% on average in the projected volumes or commercial margins; (ii) an increase of 12.1 percentage points in the discount rate; and (iii) a final negative nominal growth rate of 26.2%.

Goodwill allocated to the CGU European gas market increased by €45 million following the acquisition of the residual 51% interest in Gas Supply Company Thessaloniki-Thessalia SA operating in Greece, previously participated with a 49% of the share capital. The residual amount of €95 million relates to Eni Gas & Power France SA (former Altergaz SA). The impairment review performed at the balance sheet date by using a method similar to the Domestic gas market CGU confirmed the recoverability of the carrying amount of the France gas market CGU including any allocated goodwill by using a post-tax WACC adjusted considering a country risk for France of 6.1%, while the impairment review for the Greek gas market CGU was part of the acquisition evaluation.

13 Net reversal (impairment) of tangible and intangible assets

In assessing whether impairment is required, the carrying amounts of the assets are compared with their recoverable amounts. The recoverable amount is the higher between an asset's fair value less costs to sell and its value-in-use. In the event of an asset's impairment being reversed, the reversal may not raise the carrying amount above the value it would have stood at taking into account depreciation, if no impairment had originally been recognized.

Given the nature of Eni's activities, information on asset fair value is usually difficult to obtain unless negotiations with a potential buyer are ongoing. Therefore, the recoverability is verified by estimating assets' values-in-use. The valuation is carried out for individual assets or for the smallest identifiable group of assets that generates cash inflows that are largely independent from the cash inflows from other assets, or groups of assets (cash generating unit — CGU). The Group has identified the following CGUs: (i) in the Exploration & Production segment, individual oilfields or pools of oilfields when technical, economic or contractual features make underlying cash flows interdependent; (ii) in the Gas & Power segment, in addition to the CGUs to which goodwill arisen from business combinations was allocated, electricity generation plants, international pipelines and LNG vessels; (iii) in the Refining & Marketing business line, refining plants, retail networks and assets related to other distribution channels grouped by country of operations and type of network (retail outlets located along ordinary routes and high-ways, wholesale facilities); and (iv) the Chemical business line has been assessed to be a single CGU.

The value-in-use is calculated by discounting the estimated future cash flows deriving from the continuing use of the CGUs and, if significant and reasonably determinable, the cash flows deriving from disposal at the end of their useful lives. Cash flows are determined based on the best information available at the time of the assessment. Cash flow projections for the first four years of each CGU evaluation are extracted from the Company's four-year plan adopted by the top management. The plan includes data points on expected oil&gas production volumes, sales volumes, capital expenditure, operating costs and margins and industrial and marketing set-up, as well as trends on the main macroeconomic variables, including inflation, nominal interest rates and exchange rates. The estimation of CGUs' terminal values is based on cash flow projections beyond the four-year plan horizon, which are estimated based on management's long-term assumptions regarding the main macroeconomic variables (inflation rates, commodity prices, etc.) and considering the expected useful lives of the Company's CGUs and certain assumptions regarding future trends in revenues and costs. In the case of the oil&gas CGUs, management assumed the residual life of the reserves and the associated projections of operating costs and development expenditures. The CGUs of the Refining & Marketing business line and power plants are evaluated based on the plant economic and technical life and the associated, normalized projections of operating costs and expenditures to support plant efficiency. The CGUs of the gas market business to which goodwill has been allocated are evaluated based on the perpetuity method of the last year-plan result assuming nominal growth rates equal to 0%. The terminal value of the Chemical business integrated CGU considers the economic useful lives of the underlying assets and factors a normalized EBITDA (to reflect the cyclicality of the sector) defined based on the average contribution margin of the plan. In projecting future commodity prices, management assumed the price scenario adopted for the economic and financial projections of the Company's four-year industrial plans and for the assessment of capital projects returns. The Company's price scenario is approved by the Board of Directors and is based on internal assumptions about future trends in the fundamentals of demand and supply of crude oil and other commodities as benchmarked against the market consensus forecasts and on forward prices of commodities for future delivery in case the level of liquidity and reliability of future contracts is deemed fair.

Values-in-use is estimated by discounting post-tax cash flows at a rate, which corresponds for the Exploration & Production segment and Refining & Marketing business line to the Company's weighted average cost of capital (WACC) net of specific risk factors attributable to the Gas & Power segment and the

Chemical business line, the WACC of which is assessed on a stand-alone basis. Then the discount rates are adjusted to factor in risks specific to each country of activity (adjusted post-tax WACC). Post-tax cash flows and discount rates were adopted as they resulted in an assessment that substantially approximated a pre-tax assessment.

The framework of impairment indicators of exogenous origin remained substantially stable compared to the context relating to the assessments performed in the previous year.

In the final part of 2018, after touching a multi-year high at approximately 85 $/BBL, the Brent crude oil price made a sharp downturn driven by a slowdown in macroeconomic growth, oversupplies and uncertainties tied with the trade dispute between USA and China, the Brexit and local geopolitical crises. In spite of the remarkable correction in oil prices which declined by more than 20 $/BBL to close the year at approximately 60 $/BBL, based on the review of market fundamentals in the medium-long term which remain supportive of continued demand growth, as well as willingness on part of producers to maintain oil markets in balance and the market view of financial analysts and industry observers, management retained a long-term Brent price of 70 $/BBL in real terms 2022, substantially in line with the assumption made in the annual report 2017, on which basis management performed the 2018 assets impairment review and elaborated financial projections for the four-year plan 2019-2022. Prices of natural gas in Europe are projected to reach a higher level than in previous planning assumptions driven by an improved balance between gas demand and supplies supported by a continuing decline in continental mature fields production and the phase-out of nuclear and coal power plants. The SERM benchmark refining margin is projected unchanged from the previous plan at approximately 5 $/BBL in the long term, based on expectations of continuing competitive pressures in Europe from cheaper products streams imported from USA and Middle East, the effects of which will be mitigated by enactment of stricter environmental regulations on the sulphur content of marine fuels effective from 2020. Projections of margins for the main petrochemicals commodities were scaled down due to management's expectations of continued competitive pressures in European markets from more competitive producers based in USA and Middle East and a slowdown in end markets. However, the projections of margins in the petrochemicals business determined only a modest reduction in the value-in-use of the Company's petrochemicals CGU because the impairment review is based on a normalized scenario which factors in the cyclicality of the industry.

Moreover, although at the balance sheet date the market capitalization of Eni was about 3% lower than the book value of consolidated net assets, this tendency registered a significant trend reversal and, at the date of approval of the Financial Statements by the Board of Directors, the market capitalization exceeded the book value by about 10%.

The management tested for impairment the totality of the Group's fixed assets as provided by the Company's internal guidelines.

The 2018 WACC of Eni, which is the driver for calculating the post-tax WACC of the oil&gas and refining business CGUs to assess their value-in-use, recorded an increase 0.5 percentage point to 7.3% compared to 2017. This increase was driven by the projections of higher risk-free yields that Eni's methodology links to ten-year Italian government bonds. The WACC used in the Gas & Power segment and the Chemical business, subject to separate valuation compared to the Eni's assessment, resulted unchanged from 2017. The adjusted WACC rates for 2018 highlighted a certain dispersion of values compared to the mean, reflecting large differences in the country risk premiums which were affected by ongoing developments in each country operating environment. The post-tax WACC rates used for impairment test purposes in 2018 ranged from 6.2% to 16.0% in the Exploration & Production segment.

In the Exploration & Production segment the Company recorded impairment losses before taxes for €1,025 million driven by a lower-than-expected performance at certain oilfields, particularly in Congo and USA, a deteriorated operating environment of a specific project and alignment to fair value of assets divested or held for sale in Croatia and Ecuador. These losses were partially offset by reversals of prior-year impairment losses for €299 million due to better gas prices in Europe and reduced country risk premiums in certain locations. The post-tax WACC relating to impairment losses/reversals of impairments of more than €100 million amounted to 6%, corresponding to pre-tax rates ranging from 6% to 9%.

In the Refining & Marketing business line the Company recorded impairment losses for €156 million related to the investments of the year for compliance and stay-in-business related to CGUs fully impaired in prior years for which profitability expectations have remained unchanged from the previous-year impairment review.

In the Gas & Power segment the Company recorded a reversals of impairment losses at a gas transportation asset for €66 million driven by a lower discount rate adjusted for the country risk. In the power business, reversals and impairments relating to each individual plant resulted offset.

14 Investments

Equity-accounted investments

(€ million)	2018 Investments in unconsolidated entities controlled by Eni	2018 Joint ventures	2018 Associates	2018 Total	2017 Investments in unconsolidated entities controlled by Eni	2017 Joint ventures	2017 Associates	2017 Total
Carrying amount – beginning of the year	**116**	**2,332**	**1,063**	**3,511**	**168**	**2,675**	**1,197**	**4,040**
Changes in accounting policies (IFRS 9 and 15)		(34)	(3)	**(37)**				
Carrying amount restated – beginning of the year	**116**	**2,298**	**1,060**	**3,474**	**168**	**2,675**	**1,197**	**4,040**
Additions and subscriptions		28	92	**120**		63	444	**507**
Divestments and reimbursements	(33)	(3)	(115)	**(151)**			(462)	**(462)**
Share of profit of equity-accounted investments	8	16	385	**409**	9	49	66	**124**
Share of loss of equity-accounted investments	(5)	(415)	(10)	**(430)**	(7)	(340)	(6)	**(353)**
Deduction for dividends	(6)	(19)	(25)	**(50)**	(32)	(41)	(13)	**(86)**
Changes in the scope of consolidation		3,448		**3,448**	2			**2**
Currency translation differences	2	25	54	**81**	(13)	(127)	(128)	**(268)**
Other changes	13	119	11	**143**	(11)	53	(35)	**7**
Carrying amount – end of the year	**95**	**5,497**	**1,452**	**7,044**	**116**	**2,332**	**1,063**	**3,511**

Acquisitions and share capital increases mainly related to: (i) the capital contribution to Coral FLNG SA (€48 million) which is engaged in the development of a floating production and storage unit of LNG in natural gas-rich Area 4, offshore Mozambique; (ii) the acquisition for €42 million of a 33.72% interest in Commonwealth Fusion System Llc (CFS), a company created as a spin-out of the Massachusetts Institute of Technology for the development of the technology of power generation from fusion.

Divestments and reimbursements related to the capital reimbursement of Angola LNG Ltd for €95 million.

The share of Eni's profit of equity-accounted entities related for €353 million to the equity result of Angola LNG Ltd, driven by a reversal of about €260 million of prior-year impairment losses of the LNG project. The economics of the project improved due to the favorable outcome of an arbitration proceeding which established the settlement of a contract to utilize the re-gasification terminal of Pascagoula owned by Gulf Energy Ltd, where the fees associated with the contract were previously discounted in the future cash flow of the upstream project and of the related downstream activity of gas marketing. The outcome of the arbitration led to the recognition of an equivalent expense through loss.

The accounting under the equity method of Saipem SpA resulted in a loss of €146 million due to the recognition by the investee of restructuring costs and impairment losses of assets. As of December 31, 2018, the book value of the investment in Saipem amounting to €1,228 million, which was aligned to the corresponding share of the net assets of the investee, exceeded by approximately 22% the fair value represented by the market capitalization of Saipem share. Considering this impairment indicator and ongoing uncertainties surrounding a recovery in the investing cycle of oil companies and competitive pressure in the E&C sector, management performed an impairment review of the investment to assess its recoverability based on an internal financial model of future cash flows of Saipem estimated based on financial projections made by the sell-side analysts who cover the Saipem share, publicly available data on Saipem and the observed historical correlation which link the Saipem turnover to crude oil prices and spending in capital projects made by oil companies. This review supported the book value of the investment. At date of approval of the financial statements, the book value of the investment exceeded by approximately 23% the fair value represented by the market capitalization.

Share of losses of equity-accounted investments included a loss of €219 million accounted at the joint ventures with the Venezuelan state-owned company PDVSA PetroJunín SA (Eni's interest 40%) and Cardón IV SA (Eni's interest 50%), which are operating the onshore heavy-oil Junín field and the Perla gas field respectively. The loss was driven by the de-booking of the project's undeveloped proved reserves (down by 106 million boe) due to a deteriorated operating environment, as required by the U.S. SEC rules.

Deduction for dividends related for €24 million to United Gas Derivatives Co.

Other increases included for €3,498 million the initial recognition of Eni's participating interest in the joint venture Vår Energi AS (69.60%), which was established following the business combination between the former Eni subsidiary Eni Norge AS and Point Resources AS. The joint venture will be equity-accounted. The book value of the joint venture equals Eni's share of the fair values of the combined net assets.

Net carrying amount of equity-accounted investments in related to the following:

	December 31, 2018		December 31, 2017	
(€ million)	Net carrying amount	% of the investment	Net carrying amount	% of the investment
Investments in unconsolidated entities controlled by Eni				
Eni BTC Ltd	31	100.00	63	100.00
Other investments (*)	64		53	
	95		**116**	
Joint ventures				
Vår Energi AS	3,498	69.60		
Saipem SpA	1,228	30.99	1,413	31.00
Unión Fenosa Gas SA	335	50.00	350	50.00
Gas Distribution Company of Thessaloniki – Thessaly SA	137	49.00	137	49.00
Cardón IV SA	98	50.00		
Lotte Versalis Elastomers Co Ltd	75	50.00	114	50.00
PetroJunín SA	47	40.00	210	40.00
AET – Raffineriebeteiligungsgesellschaft mbH	32	33.33	32	33.33
Other investments (*)	47		76	
	5,497		**2,332**	
Associates				
Angola LNG Ltd	1,106	13.60	802	13.60
Coral FLNG SA	102	25.00	54	25.00
Novamont SpA	67	25.00	71	25.00
United Gas Derivatives Co	62	33.33	82	33.33
Commonwealth Fusion Systems Llc	42	33.72		
Other investments (*)	73		54	
	1,452		**1,063**	
	7,044		**3,511**	

(*) Each individual amount included herein was lower than €25 million.

Results of equity-accounted investments by segment are disclosed in note 35 — Segment information and information by geographical area.

The carrying amounts of equity-accounted investments included differences between the purchase price of acquired interests and their underlying book value of net assets amounting to €58 million, related to Novamont SpA for €43 million and Unión Fenosa Gas SA for €15 million. These surpluses were driven by the long-term profitability outlook of the acquired companies at the time of the acquisition.

As of December 31, 2018, the market value of the investments listed in regulated stock markets was as follows:

	Saipem SpA
Number of shares held	308,767,968
% of the investment	30.99
Share price (€)	3.265
Market value (€ million)	1,008
Book value (€ million)	1,228

Additional information is included in note 37 — Other information about investments.

Other investments

(€ million)	2018	2017
Carrying amount – beginning of the year	**219**	**276**
Changes in accounting policies (IFRS 9)	681	
Carrying amount restated – beginning of the year	**900**	**276**
Additions and subscriptions	5	3
Change in the fair value	15	
Divestments and reimbursements	(22)	(19)
Currency translation differences	31	(23)
Other changes	(10)	(18)
Carrying amount – end of the year	**919**	**219**

In applying IFRS 9, minor investments were recognized at fair value resulting in an asset write-up of €681 million as of January 1, 2018. Those investments in equity instruments were previously accounted for under IAS 39 which permitted entities to measure unquoted investments in equity instruments at cost if their fair value could not be determined reliably. This increase related to: (i) Nigeria LNG Ltd for €511 million (€99 million at December 31, 2017). The investment book value as of December 31, 2018 was €651 million net of the dividends paid in the year; (ii) Saudi European Petrochemical Co 'IBN ZAHR' for €130 million (€13 million at December 31, 2017). The investment book value as of December 31, 2018 was €144 million net of the dividends paid in the year.

The fair value of the main non-controlling interests in unquoted undertakings, classified within level 3 of the fair value hierarchy, was estimated based on a methodology that combines expected additional earnings and sum-of-the-parts measurements (so-called residual income approach) and takes into account, inter alia, the following inputs: (i) expected results, as a gauge of the future profitability of the investees, derived from the business plans, but adjusted, where appropriate, to include the assumptions that market participants would incorporate; (ii) the cost of capital, adjusted to include the risk premium of the specific country in which each investee operates. Changes of 1% of the cost of capital considered in the valuation do not produce significant changes at the fair value evaluation.

Dividends paid by those investments are disclosed in note 31 — Income (expense) from investments.

15 Other financial assets

(€ million)	December 31, 2018 Current	December 31, 2018 Non-current	December 31, 2017 Current	December 31, 2017 Non-current
Long-term financing receivables held for operating purposes	61	1,189	23	1,602
Short-term financing receivables held for operating purposes	51		84	
	112	**1,189**	**107**	**1,602**
Financing receivables held for non-operating purposes	188		209	
	300	**1,189**	**316**	**1,602**
Securities held for operating purposes		64		73
	300	**1,253**	**316**	**1,675**

Financing receivables are stated net of allowance for doubtful accounts as follows:

(€ million)	Allowance for doubtful accounts of financing receivables
Carrying amount at December 31, 2017	**730**
Additions	279
Deductions	(596)
Currency translation differences	17
Carrying amount at December 31, 2018	**430**

Financing receivables held for operating purposes of €1,301 million (€1,709 million at December 31, 2017) related principally to funds provided to joint ventures and associates in the Exploration & Production segment (€1,075 million) and the Gas & Power segment (€103 million). The greatest exposure is towards the joint venture Cardón IV SA (Eni's interest 50%) in Venezuela, which is currently operating the Perla offshore gas field, for €705 million at December 31, 2018 (€955 million at December 31, 2017). The recoverability of those assets was assessed considering the performance of the industrial initiatives financed in addition to other factors.

Financing receivables held for operating purposes due beyond five years amounted to €1,088 million (€1,393 million at December 31, 2017).

The fair value of non-current financing receivables held for operating purposes of €1,188 million has been estimated based on the present value of expected future cash flows discounted at rates ranging from -0.2% to 2.9% (-0.2% and 2.5% at December 31, 2017). This valuation methodology does not apply to assess the recoverability of the financial loan granted to the joint venture Cardón IV SA to fund the development projects carried out by the venture, which can be assimilated to net capital employed. The recoverability of this financing loans depends on the future cash flows of the industrial project, which are exposed to a credit risk given the difficult financial condition of Venezuela. In assessing the recoverability of the loan, management carried out an appreciation of the risk to convert in cash the project's future revenues by projecting a deferral in the timing of revenues collection and discounting the resulting future cash flows at a rate adjusted for the Country risk that factors in the deteriorated operating environment of the Country. The outcomes of the assessment confirmed the carrying amount of the financial loan.

The recoverability of other long-term financial assets was assessed by considering the expected probability default in the next twelve months only, as the creditworthiness suffered no significant deterioration in the reporting period.

Additions to the allowance for doubtful accounts related to a loss taken at a financing receivable granted to a joint venture in Russia engaged in the execution of an exploratory project in the Black Sea due to the unsuccessful outcome of the initiative.

Financing receivables held for non-operating purposes related to bank deposits with the purpose to invest cash surpluses and restricted deposits in escrow to guarantee transactions on derivative contracts.

Financing receivables held for operating purposes were denominated in euro and U.S. dollar for €188 million and €1,299 million, respectively.

Securities held for operating purpose related to listed bonds issued by sovereign states (listed bonds issued by sovereign states for €69 million and by the European Investment Bank for €4 million at December 31, 2017).

Securities for €20 million (same amount as of December 31, 2017) were pledged as guarantee of the deposit for gas cylinders as provided for by the Italian law.

The following table analyses securities per issuing entity:

	Amortized cost (€ million)	Nominal value (€ million)	Fair Value (€ million)	Nominal rate of return (%)	Maturity date	Rating-Moody's	Rating-S&P
Sovereign states							
Fixed rate bonds							
Italy	24	24	25	from 0.20 to 4.75	from 2019 to 2025	Baa3	BBB
Others (*)	29	29	29	from 0.05 to 4.40	from 2019 to 2023	from Aa3 to Baa1	from AA to A-
Floating rate bonds							
Italy	8	8	8		from 2019 to 2020	Baa3	BBB
Others (*)	3	3	3		2022	Baa3	BBB-
Total sovereign states	**64**	**64**	**65**				

(*) Amounts included herein are lower than €25 million.

Securities having a maturity within five years amounted to €63 million.

The fair value of securities was derived from quoted market prices.

Receivables with related parties are described in note 36 — Transactions with related parties.

16 Trade and other payables

As of January 1, 2018, the effects of the application of IFRS 15 are the followings:

(€ million)	Trade payables	Down payments and advances from customers	Down payments and advances from joint venture partners in exploration and production	Other payables	Trade and other payables
Carrying amount at December 31, 2017	**10,890**	**545**	**252**	**5,061**	**16,748**
Changes in accounting principles (IFRS 15) ..				(113)	**(113)**
Reclassification to other current liabilities (IFRS 15)		(545)		(785)	**(1,330)**
Carrying amount at January 1, 2018	**10,890**		**252**	**4,163**	**15,305**

The application of IFRS 15 determined a decrease in the stated amount of payables recognized in connection with lifting imbalances in the Exploration & Production segment for €113 million in applying the sales method in lieu of the entitlement method.

The reclassification to other current liabilities (IFRS 15) related to: (i) lifting imbalances of the Exploration & Production segment recognized by using the sales method for €785 million; (ii) down payments and advances from customers reclassified as liabilities from contracts with customers.

More information about the application of IFRS 9 and IFRS 15 is reported in note 3 — Changes in accounting policies.

The break-down of trade and other payables is the following:

(€ million)	December 31, 2018	December 31, 2017
Trade payables	11,645	10,890
Down payments and advances from customers		545
Down payments and advances from partners in exploration & production activities	207	252
Payables for purchase of non-current assets	2,530	2,094
Payables due to partners in exploration & production activities	1,151	1,968
Other payables	1,214	999
	16,747	**16,748**

Trade payables were denominated in euro for €6,484 million and in U.S. dollar for €9,403 million.

Because of the short-term maturity and conditions of remuneration of trade payables, the fair values approximated the carrying amounts.

Payables due to related parties are described in note 36 — Transactions with related parties.

17 Other liabilities

	December 31, 2018		December 31, 2017	
(€ million)	Current	Non-current	Current	Non-current
Fair value of derivatives financial instruments	1,445	40	1,011	91
Liabilities from contracts with customers	1,108	518		
Cautionary deposits		268		255
Other liabilities	1,427	676	504	1,133
	3,980	**1,502**	**1,515**	**1,479**

In applying IFRS 15: (i) liabilities from contracts with customers included the reclassification as of January 1, 2018, from the item Trade and other liabilities of down payments and advances from customers of €545 million; (ii) other current liabilities included the reclassification as of January 1, 2018, from the item Trade and other receivables of the lifting imbalances in the Exploration & Production segment for €785 million following the adoption of the sales method.

Fair value related to derivative financial instruments is disclosed in note 23 — Derivative financial instruments and hedge accounting.

Liabilities from contracts with customer of €1,626 million included: (i) advances denominated in local currency of €716 million relating to future supplies of equity hydrocarbons to our Egyptian State-owned partners in relation to the operations of Eni's Concession Agreements in the Country for the next four-year period and in particular, among these, the Zohr project; (ii) the current portion of advances received by Engie SA (former Suez) relating to a long-term agreement for supplying natural gas and electricity for €66 million; the non-current portion amounted to €518 million.

Cautionary deposits related to deposits from retail customers for the supply of gas and electricity of €233 million (€215 million at December 31 2017).

Other current liabilities included overlifting imbalances of the Exploration & Production segment for €1,004 million.

Other non-current liabilities included tax liabilities for €61 million (€45 million at December 31, 2017) and other debts for €155 million (€45 million at December 31 2017).

Transactions with related parties are described in note 36 — Transactions with related parties.

18 Financial liabilities

(€ million)	December 31, 2018 Short-term debt	Current portion of long-term debt	Long-term debt	Total	December 31, 2017 Short-term debt	Current portion of long-term debt	Long-term debt	Total
Banks	383	768	2,710	3,861	201	801	3,200	4,202
Ordinary bonds		2,781	16,923	19,704		1,445	16,520	17,965
Convertible bonds			390	390			387	387
Commercial papers	915			915	1,664			1,664
Other financial institutions	884	52	59	995	377	40	72	489
	2,182	**3,601**	**20,082**	**25,865**	**2,242**	**2,286**	**20,179**	**24,707**

Financial liabilities included an increase of €1,158 million driven by: (i) new issuances net of repayments made of €320 million; (ii) currency translation differences relating to companies having debt denominated in currency other than the functional currency for €314 million (iii) the de-recognition of Eni Norge AS cash and cash equivalents for €494 million due to the loss of control on the former subsidiary, which were deposited at the Group's financial companies.

Commercial papers were issued by the Group's financial subsidiaries.

The following table reflects long-term debt and current portion of long-term debt as of December 31, 2018 by maturity:

(€ million)	Long-term debt 2020	2021	2022	2023	After	Total
Banks	556	345	393	829	587	**2,710**
Ordinary bonds	2,391	921	698	1,858	11,055	**16,923**
Convertible bonds			390			**390**
Other financial institutions	9	10	9	11	20	**59**
	2,956	**1,276**	**1,490**	**2,698**	**11,662**	**20,082**

Eni entered into long-term borrowing facilities with the European Investment Bank. These borrowing facilities are subject to the maintenance of a minimum level of credit rating. According to the agreements, should the Company lose the minimum credit rating, new guarantees could be required to be agreed upon with the European Investment Bank. In addition, Eni entered into long and medium-term facilities subject to the maintenance of certain financial ratios based on the Consolidated Financial Statements of Eni with Citibank Europe Plc, whose non-compliance allows the bank to request an early repayment. At December 31, 2018, debts subjected to restrictive covenants amounted to €1,337 million (€1,664 million at December 31, 2017). Eni was in compliance with those covenants.

Ordinary bonds consisted of bonds issued within the Euro Medium Term Notes Program for a total of €16,904 million and other bonds for a total of €2,800 million.

The following table provides a breakdown of ordinary bonds by issuing entity, maturity date, interest rate and currency as of December 31, 2018:

(€ million)	Amount	Discount on bond issue and accrued expense	Total	Currency	Maturity from	Maturity to	Rate % from	Rate % to
Issuing entity								
Euro Medium Term Notes								
Eni SpA	1,500	17	1,517	EUR		2019		4.125
Eni SpA	1,200	16	1,216	EUR		2025		3.750
Eni SpA	1,000	38	1,038	EUR		2020		4.250
Eni SpA	1,000	27	1,027	EUR		2029		3.625
Eni SpA	1,000	19	1,019	EUR		2020		4.000
Eni SpA	1,000	9	1,009	EUR		2023		3.250
Eni SpA	1,000	8	1,008	EUR		2026		1.500
Eni SpA	900	(5)	895	EUR		2024		0.625
Eni SpA	800	2	802	EUR		2021		2.625
Eni SpA	800	(1)	799	EUR		2028		1.625
Eni SpA	750	14	764	EUR		2019		3.750
Eni SpA	750	8	758	EUR		2024		1.750
Eni SpA	750	5	755	EUR		2027		1.500
Eni SpA	700	1	701	EUR		2022		0.750
Eni SpA	650	2	652	EUR		2025		1.000
Eni SpA	600	(5)	595	EUR		2028		1.125
Eni Finance International SA	335	15	350	GBP	2019	2021	4.750	5.000
Eni Finance International SA	295	4	299	EUR	2028	2043	3.875	5.441
Eni Finance International SA	167		167	YEN	2019	2037	1.955	2.810
Eni Finance International SA	1,528	5	1,533	USD	2026	2027		variable
	16,725	**179**	**16,904**					
Other bonds								
Eni SpA	873	2	875	USD		2023		4.000
Eni SpA	873	1	874	USD		2028		4.750
Eni SpA	393	4	397	USD		2020		4.150
Eni SpA	305	1	306	USD		2040		5.700
Eni USA Inc	349	(1)	348	USD		2027		7.300
	2,793	**7**	**2,800**					
	19,518	**186**	**19,704**					

As of December 31, 2018, ordinary bonds maturing within 18 months amounted to €4,596 million. During 2018, new bonds issued amounted to €2,844 million.

The following table provides a breakdown of convertible bonds issued by Eni SpA as of December 31, 2018:

(€ million)	Amount	Discount on bond issue and accrued expense	Total	Currency	Maturity	Rate %
Eni SpA	400	(10)	390	EUR	2022	0.000

The non-dilutive equity-linked bond issued provides for by a redemption value linked to the market price of Eni's shares. The bondholders have "conversion" rights at certain times and/or in the presence of certain events, while the bonds will be cash-settled. Accordingly, to hedge its exposure, Eni purchased cash-settled call options relating to Eni shares that will be settled on a net cash basis. The convertible bond is measured at amortized cost. The conversion option, embedded in the financial instrument issued, and the call option on Eni's shares acquired are valued at fair value with effects recognized through profit and loss.

Eni has in place a program for the issuance of Euro Medium Term Notes up to €20 billion, of which €16.7 billion were drawn as of December 31, 2018.

The following table provides a breakdown by currency of long-term debt, its current portion and the related weighted average interest rates:

	December 31, 2018				December 31, 2017			
	Short term debt (€ million)	Average rate (%)	Long term debt and current portion of long term debt (€ million)	Average rate (%)	Short term debt (€ million)	Average rate (%)	Long term debt and current portion of long term debt (€ million)	Average rate (%)
Euro	680	1.9	18,635	2.3	904	0.5	20,094	2.4
U.S. dollar	1,007	2.5	4,530	4.3	1,329	1.8	1,694	4.8
Other currencies	495	1.0	518	4.2	9	(0.7)	677	4.7
	2,182		**23,683**		**2,242**		**22,465**	

As of December 31, 2018, Eni retained undrawn uncommitted borrowing facilities amounting to €12,484 million (€11,584 million at December 31, 2017) and undrawn long-term committed borrowing facilities of €5,214 million (€5,802 at December 31, 2017). Those facilities bore interest rates reflecting prevailing conditions on the marketplace.

Fair value of long-term debt, including the current portion of long-term debt is described below:

(€ million)	December 31, 2018	December 31, 2017
Ordinary bonds	20,257	19,219
Convertible bonds	399	410
Banks	3,445	4,021
Other financial institutions	111	114
	24,212	**23,764**

Fair value of financial debt was calculated by discounting the expected future cash flows at discount rates ranging from -0.2% to 2.9% (-0.2% and 2.5% at December 31, 2017).

Because of the short-term maturity and conditions of remuneration of short-term debts, the fair value approximated the carrying amount.

Changes in borrowings are provided below:

(€ million)	Long-term debt and current portion of long-term debt	Short-term debt	Total
Carrying amount at December 31, 2017	**22,465**	**2,242**	**24,707**
Cash flows	1,033	(713)	**320**
Currency translation differences	126	188	**314**
Changes in the scope of consolidation		494	**494**
Other non-monetary changes	59	(29)	**30**
Carrying amount at December 31, 2018	**23,683**	**2,182**	**25,865**

Transactions with related parties are described in note 36 — Transactions with related parties

19 Information on net borrowings

In assessing its capital structure, Eni uses net borrowings, which is a non-GAAP financial measure. Eni calculates net borrowings as total finance debt (short-term and long-term debt) derived from its Consolidated Financial Statements prepared in accordance with IFRS less: cash and cash equivalents, held-for-trading securities and certain highly-liquid investments not related to operations including, among others, non-operating financing receivables. Held-for-trading securities are part of a strategic reserve of liquidity that management has established by reinvesting proceeds from the Group disposal plans and is intended to provide a certain degree of financial flexibility in case of a prolonged price downturn, tight financial markets or in view of other Company's purposes. Non-operating financing receivables consist mainly of deposits with banks and other financing institutions and deposits in escrow. These assets are generally intended to absorb temporary surpluses of cash as part of the Company's ordinary management of financing activities.

Management believes that net borrowings is a useful measure of Eni's financial condition as it provides insight about the soundness of Eni's capital structure and the ways by which Eni's operating assets are financed.

	December 31, 2018			December 31, 2017		
(€ million)	Current	Non-current	Total	Current	Non-current	Total
A. Cash and cash equivalents	10,836		10,836	7,363		7,363
B. Held-for-trading financial assets	6,552		6,552	6,012		6,012
C. Available-for-sale financial assets				207		207
D. Liquidity (A+B+C)	**17,388**		**17,388**	**13,582**		**13,582**
E. Financing receivables	**188**		**188**	**209**		**209**
F. Short-term debt towards banks	383		383	201		201
G. Long-term debt towards banks	768	2,710	3,478	801	3,200	4,001
H. Bonds	2,781	17,313	20,094	1,445	16,907	18,352
I. Short-term debt towards related parties	661		661	164		164
L. Other short-term liabilities	1,138		1,138	1,877		1,877
M. Other long-term liabilities	52	59	111	40	72	112
N. Total borrowings (F+G+H+I+L+M)	**5,783**	**20,082**	**25,865**	**4,528**	**20,179**	**24,707**
O. Net borrowings (N-D-E)	**(11,793)**	**20,082**	**8,289**	**(9,263)**	**20,179**	**10,916**

Financial assets held for trading are disclosed in note 6 — Financial assets held for trading.

Current financing receivables are disclosed in note 15 — Other financial assets.

20 Provisions for contingencies

(€ million)	Provision for site restoration, abandonment and social projects	Environmental provision	Provision for litigations	Provision for taxes	Loss adjustments and actuarial provisions for Eni's insurance companies	Provision for losses on investments	Provision for OIL insurance cover	Provision for redundancy incentives	Provision for disposal and restructuring	Provision for onerous contracts	Other(*)	Total
Carrying amount at December 31, 2017	**8,126**	**2,653**	**1,107**	**527**	**205**	**182**	**76**	**140**	**65**	**60**	**306**	**13,447**
New or increased provisions		299	148	73	493	48	51	9	19		223	**1,363**
Initial recognition and changes in estimates	(502)											**(502)**
Accretion discount	259	(12)	2									**249**
Reversal of utilized provisions	(190)	(287)	(214)	(118)	(481)			(17)	(14)	(22)	(100)	**(1,443)**
Reversal of unutilized provisions		(33)	(289)	(31)		(1)		(17)			(18)	**(389)**
Changes in the scope of consolidation	(1,024)	(11)	(1)	(8)				(5)			(2)	**(1,051)**
Currency translation differences	153		34	17		2					4	**210**
Other changes	(45)	(14)	37	(20)	110	(27)	3	(2)	(4)		(36)	**2**
Carrying amount at December 31, 2018	**6,777**	**2,595**	**824**	**440**	**327**	**204**	**130**	**108**	**66**	**38**	**377**	**11,886**

(*) Each individual amount included herein was lower than €50 million.

The Group makes full provision for the future costs of decommissioning oil and natural gas wells, facilities and related pipelines on a discounted basis upon installation. The decommissioning provisions included the discounted estimated costs that the Company expects to incur for decommissioning oil and natural gas production facilities at the end of the producing lives of fields, well-plugging, abandonment and site restoration of the Exploration & Production segment for €6,266 million. Estimate revisions of €502 million were driven by an increase in the discount rate curve in particular for the U.S. dollar. Such increase was partially offset by the recognition of new decommissioning obligations due to the activity of the year and upward revisions of cost estimates. The unwinding of discount recognized through profit and loss for €259 million was determined based on discount rates ranging from -0.2% to 6.1% (from -0.01% to 5.98% at December 31, 2017). Main expenditures associated with decommissioning operations are expected to be incurred over a 45-year period.

Provisions for environmental risks included the estimated costs for environmental clean-up and remediation of soil and groundwater in areas owned or under concession where the Group performed in the past industrial operations that were progressively divested, shut down, dismantled or restructured. The provision was accrued because at the balance sheet date there is a legal or constructive obligation for Eni to carry out environmental clean-up and remediation and the expected costs can be estimated reliably. The provision included the expected charges associated with strict liability related to obligations of cleaning up and remediating polluted areas that met the parameters set by the law at the time when the pollution occurred, or because Eni assumed the liability borne by other operators when the Company acquired or otherwise took over site operations. Those environmental provisions are recognized when an environmental project is approved by or filed with the relevant administrative authorities or a constructive obligation has arisen whereby the Company commits itself to performing certain cleaning-up and restoration projects and a reliable cost estimation is available. At December 31, 2018, environmental provision primarily related to Syndial SpA for €2,009 million and to the Refining & Marketing business line for €348 million.

The litigation provision comprised the expected liabilities associated with legal proceedings and other matters arising from contractual claims, contract renegotiations, including arbitration, fines and penalties due to antitrust proceedings and administrative matters. These provisions represented the Company's best estimate of the expected, probable liabilities associated with pending litigation and commercial disputes and primarily related to the Exploration & Production segment for €653 million. Utilizations of €503 million mainly related to the definition of a price revision relating to a gas sale contract with a long-term buyer, the effect of which was compensated by the reduction of the receivable due by the gas supplier recognized in other non-current assets.

Provisions for taxes included the estimated charges that the Company expects to incur to settle uncertain tax matters and tax claims from authorities in connection the application of current tax rules at certain Italian and non-Italian subsidiaries in the Exploration & Production segment (€397 million).

Loss adjustments and actuarial provisions of Eni's insurance company Eni Insurance DAC represented the estimated liabilities accrued on the basis for third parties claims. Against such liability was recorded receivables of €236 million recognized towards insurance companies for reinsurance contracts.

Provisions for losses on investments included provisions relating to investments whose loss exceeds the equity and primarily related to Industria Siciliana Acido Fosforico — ISAF — SpA (in liquidation) for €114 million.

Provisions for the OIL mutual insurance scheme included the estimated future increase of insurance premiums which will be charged to Eni in the next five years and that accrued at the reporting date because of the effective accident rate occurred in past reporting periods.

Provisions for redundancy incentives were recognized due to a restructuring program involving the Italian personnel related to past reporting periods.

21 Provisions for employee benefits

(€ million)	December 31, 2018	December 31, 2017
Italian defined benefit plans	275	284
Foreign defined benefit plans	385	409
FISDE, foreign medical plans and other	148	135
Defined benefit plans	**808**	**828**
Other benefit plans	309	194
Provision for employee benefits	**1,117**	**1,022**

The liability relating to Eni's commitment to cover the healthcare costs of personnel is determined on the basis of the contributions paid by the Company.

Other employee benefit plans related to deferred monetary incentive plans for €136 million, the *isopensione* plans of Eni gas e luce SpA for €132 million, jubilee awards for €22 million, long-term incentive plan still outstanding for €8 million and other long-term plans for €11 million.

Present value of employee benefits, estimated by applying actuarial techniques, consisted of the following:

	December 31, 2018						December 31, 2017					
(€ million)	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Defined benefit plans	Other benefit plans	Total	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Defined benefit plans	Other benefit plans	Total
Present value of benefit liabilities at beginning of year	**284**	**997**	**135**	**1,416**	**194**	**1,610**	**298**	**895**	**136**	**1,329**	**158**	**1,487**
Current cost		27	2	**29**	**42**	**71**		24	2	**26**	54	**80**
Interest cost	4	31	2	**37**	**1**	**38**	3	29	2	**34**	1	**35**
Remeasurements:	1	(25)	13	**(11)**	**30**	**19**	(6)	54	(1)	**47**	3	**50**
- actuarial (gains) losses due to changes in demographic assumptions								*(14)*		***(14)***		*(14)*
- actuarial (gains) losses due to changes in financial assumptions		*(31)*	*1*	***(30)***	*29*	***(1)***	*(5)*	*71*		***66***	*3*	***69***
- experience (gains) losses	*1*	*6*	*12*	***19***	*1*	***20***	*(1)*	*(3)*	*(1)*	***(5)***		***(5)***
Past service cost and (gains) losses settlements		2	1	**3**	**115**	**118**		(1)	2	**1**	28	**29**
Plan contributions:								1		**1**		**1**
- employee contributions		*1*		***1***		***1***		*1*		***1***		***1***
Benefits paid	(15)	(35)	(9)	**(59)**	**(74)**	**(133)**	(10)	(37)	(6)	**(53)**	(36)	**(89)**
Reclassification to asset held for sale		(8)		**(8)**		**(8)**		(12)		**(12)**	(2)	**(14)**
Changes in the scope of consolidation		(90)		**(90)**	**(2)**	**(92)**	(1)	(15)	(1)	**(17)**	(3)	**(20)**
Currency translation differences and other changes	1	26	4	**31**	**3**	**34**		59	1	**60**	(9)	**51**
Present value of benefit liabilities at end of year (a)	**275**	**925**	**148**	**1,348**	**309**	**1,657**	**284**	**997**	**135**	**1,416**	**194**	**1,610**
Plan assets at beginning of year		**588**		**588**		**588**		**619**		**619**		**619**
Interest income		17		**17**		**17**		20		**20**		**20**
Return on plan assets		(21)		**(21)**		**(21)**		12		**12**		**12**
Plan contributions:		25		**25**		**25**		24		**24**		**24**
- employee contributions		*1*		***1***		***1***		*1*		***1***		***1***
- employer contributions		*24*		***24***		***24***		*23*		***23***		***23***
Benefits paid		(26)		**(26)**		**(26)**		(25)		**(25)**		**(25)**
Changes in the scope of consolidation		(64)		**(64)**		**(64)**		(15)		**(15)**		**(15)**
Currency translation differences and other changes		26		**26**		**26**		(47)		**(47)**		**(47)**
Plan assets at end of year (b)		**545**		**545**		**545**		**588**		**588**		**588**
Asset ceiling at beginning of year												
Change in asset ceiling		5		**5**		**5**						
Asset ceiling at end of year (c)		**5**		**5**		**5**						
Net liability recognized at end of year (a-b+c)	**275**	**385**	**148**	**808**	**309**	**1,117**	**284**	**409**	**135**	**828**	**194**	**1,022**

Employee benefit plans included the liability attributable to partners operating in exploration and production activities of €181 million (€177 million at December 31, 2017). Eni recorded a receivable for an amount equivalent to such liability.

Costs charged to the profit and loss account consisted of the following:

(€ million)	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Defined benefit plans	Other benefit plans	Total
2018						
Current cost		27	2	**29**	42	**71**
Past service cost and (gains) losses on settlements		2	1	**3**	115	**118**
Interest cost (income), net:						
- interest cost on liabilities	*4*	*31*	*2*	***37***	*1*	***38***
- interest income on plan assets		*(17)*		***(17)***		***(17)***
Total interest cost (income), net	4	14	2	**20**	1	**21**
- of which recognized in "Payroll and related cost"					*1*	***1***
- of which recognized in "Financial income (expense)"	*4*	*14*	*2*	***20***		***20***
Remeasurements for long-term plans					30	**30**
Total	**4**	**43**	**5**	**52**	**188**	**240**
- of which recognized in "Payroll and related cost"		*29*	*3*	***32***	*188*	***220***
- of which recognized in "Financial income (expense)"	*4*	*14*	*2*	***20***		***20***
2017						
Current cost		24	2	**26**	54	**80**
Past service cost and (gains) losses on settlements		(1)	2	**1**	28	**29**
Interest cost (income), net:						
- interest cost on liabilities	*3*	*29*	*2*	***34***	*1*	***35***
- interest income on plan assets		*(20)*		***(20)***		***(20)***
Total interest cost (income), net	3	9	2	**14**	1	**15**
- of which recognized in "Payroll and related cost"					*1*	***1***
- of which recognized in "Financial income (expense)"	*3*	*9*	*2*	***14***		***14***
Remeasurements for long-term plans					3	**3**
Total	**3**	**32**	**6**	**41**	**86**	**127**
- of which recognized in "Payroll and related cost"		*23*	*4*	***27***	*86*	***113***
- of which recognized in "Financial income (expense)"	*3*	*9*	*2*	***14***		***14***

Costs of defined benefit plans recognized in other comprehensive income consisted of the following:

	2018				2017			
(€ million)	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Total	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Total
Remeasurements								
Actuarial (gains)/losses due to changes in demographic assumptions						(14)		**(14)**
Actuarial (gains)/losses due to changes in financial assumptions		(31)	1	**(30)**	(5)	71		**66**
Experience (gains) losses	1	6	12	**19**	(1)	(3)	(1)	**(5)**
Return on plan assets		21		**21**		(12)		**(12)**
Change in asset ceiling		5		**5**				
	1	**1**	**13**	**15**	**(6)**	**42**	**(1)**	**35**

Plan assets consisted of the following:

(€ million)	Cash and cash equivalents	Equity securities	Debt securities	Real estate	Derivatives	Investment funds	Assets held by insurance company	Other	Total
December 31, 2018									
Plan assets with a quoted market price ...	115	37	238	6	2	56	18	70	**542**
Plan assets without a quoted market price ...							3		**3**
	115	**37**	**238**	**6**	**2**	**56**	**21**	**70**	**545**
December 31, 2017									
Plan assets with a quoted market price ...	16	48	329	10	9	60	13	100	**585**
Plan assets without a quoted market price ...							3		**3**
	16	**48**	**329**	**10**	**9**	**60**	**16**	**100**	**588**

The main actuarial assumptions used in the measurement of the liabilities at year-end and in the estimate of costs expected for 2019 consisted of the following:

		Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Other long-term benefit plans
2018					
Discount rate ...	(%)	1.5	0.8-18.0	1.5	0.2-1.5
Rate of compensation increase ...	(%)	2.5	1.5-16.5		
Rate of price inflation ...	(%)	1.5	0.8-16.0	1.5	1.5
Life expectations on retirement at age 65 ...	(years)		13-25	24	
2017					
Discount rate ...	(%)	1.5	0.6-15.5	1.5	0.0-1.5
Rate of compensation increase ...	(%)	2.5	1.5-13.5		
Rate of price inflation ...	(%)	1.5	0.6-14.8	1.5	1.5
Life expectations on retirement at age 65 ...	(years)		13-24	24	

The following is an analysis by geographical area related to the main actuarial assumptions used in the valuation of the principal foreign defined benefit plans:

		Euro area	Rest of Europe	Africa	Other areas	Foreign defined benefit plans
2018						
Discount rate ...	(%)	1.5-1.9	0.8-2.9	3.7-18.0	8.0-13.3	**0.8-18.0**
Rate of compensation increase ...	(%)	1.5-3.0	2.5-3.8	5.0-16.5	10.0-13.3	**1.5-16.5**
Rate of price inflation ...	(%)	1.5-2.0	0.8-3.3	3.7-16.0	3.5-5.0	**0.8-16.0**
Life expectations on retirement at age 65 ...	(years)	21-22	23-25	13-17		**13-25**
2017						
Discount rate ...	(%)	1.5-1.8	0.6-2.5	3.7-15.5	4.1-8.0	**0.6-15.5**
Rate of compensation increase ...	(%)	1.5-3.0	2.5-3.7	5.0-13.5	1.5-10.0	**1.5-13.5**
Rate of price inflation ...	(%)	1.5-1.9	0.6-3.4	3.7-14.8	1.5-4.8	**0.6-14.8**
Life expectations on retirement at age 65 ...	(years)	21-24	22-24	13-17		**13-24**

The effects of a possible change in the main actuarial assumptions at the end of the year are listed below:

(€ million)	Discount rate		Rate of price inflation	Rate of increases in pensionable salaries	Healthcare cost trend rate	Rate of increases to pensions in payment
	0.5% Increase	0.5% Decrease	0.5% Increase	0.5% Increase	0.5% Increase	0.5% Increase
December 31, 2018						
Italian defined benefit plans	(12)	13	8			
Foreign defined benefit plans	(58)	65	23	15		18
FISDE, foreign medical plans and other	(7)	8			6	
Other benefit plans	(5)	3	1			
December 31, 2017						
Italian defined benefit plans	(13)	14	9			
Foreign defined benefit plans	(72)	79	24	20		13
FISDE, foreign medical plans and other	(7)	7			7	
Other benefit plans	(3)	1	1			

The sensitivity analysis was performed based on the results for each plan through assessments calculated considering modified parameters.

The amount of contributions expected to be paid for employee benefit plans in the next year amounted to €129 million, of which €48 million related to defined benefit plans.

The following is an analysis by maturity date of the liabilities for employee benefit plans and their relative weighted average duration:

(€ million)	Italian defined benefit plans	Foreign defined benefit plans	FISDE, foreign medical plans and other	Other benefit plans
December 31, 2018				
2019	15	54	9	81
2020	16	56	7	72
2021	18	63	6	67
2022	14	64	6	20
2023	11	74	6	17
2024 and thereafter	201	74	114	57
Weighted average duration (years)	10.1	17.4	12.8	2.6
December 31, 2017				
2018	16	47	7	64
2019	17	65	7	58
2020	18	70	6	45
2021	17	79	6	7
2022	14	84	6	5
2023 and thereafter	202	64	103	25
Weighted average duration (years)	10.1	17.5	12.8	2.8

22 Deferred tax assets and liabilities

(€ million)	December 31, 2018	December 31, 2017
Deferred tax liabilities, gross	7,956	10,169
Deferred tax assets available for offset	(3,684)	(4,269)
Deferred tax liabilities	**4,272**	**5,900**
Deferred tax assets, gross (net of accumulated write-down provisions)	7,615	8,347
Deferred tax liabilities available for offset	(3,684)	(4,269)
Deferred tax assets	**3,931**	**4,078**

The most significant temporary differences giving rise to net deferred tax liabilities are disclosed below:

(€ million)	Carrying amount at December 31, 2018	Carrying amount at December 31, 2017
Deferred tax liabilities		
Accelerated tax depreciation	6,612	8,323
Difference between the fair value and the carrying amount of assets acquired	849	1,106
Site restoration and abandonment (tangible assets)	85	305
Application of the weighted average cost method in evaluation of inventories	44	70
Other	366	365
	7,956	**10,169**
Deferred tax assets, gross		
Carry-forward tax losses	(5,528)	(5,240)
Site restoration and abandonment (provisions for contingencies)	(1,986)	(2,747)
Timing differences on depreciation and amortization	(2,104)	(2,164)
Accruals for impairment losses and provisions for contingencies	(1,460)	(1,404)
Impairment losses	(792)	(801)
Over/Under lifting	(604)	(395)
Employee benefits	(212)	(194)
Unrealized intercompany profits	(124)	(130)
Other	(546)	(534)
	(13,356)	**(13,609)**
Accumulated write-downs of deferred tax assets	**5,741**	**5,262**
Deferred tax assets, net	**(7,615)**	**(8,347)**

The following table summarizes the changes in deferred tax liabilities and assets:

(€ million)	**Deferred tax liabilities**	Deferred tax assets, gross	Accumulated write-downs of deferred tax assets	**Deferred tax assets, net of impairments**
2018				
Carrying amount – beginning of the year	**10,169**	**(13,609)**	**5,262**	**(8,347)**
Changes in accounting principles (IFRS 15)	37	(237)		(237)
Carrying amount restated – beginning of the year	**10,206**	**(13,846)**	**5,262**	**(8,584)**
Additions	1,147	(1,478)	253	(1,225)
Deductions	(802)	1,523	(43)	1,480
Currency translation differences	283	(278)	71	(207)
Decrease through loss of control of subsidiary	(2,778)	813		813
Other changes	(100)	(90)	198	108
Carrying amount at the end of the year	**7,956**	**(13,356)**	**5,741**	**(7,615)**
2017				
Carrying amount at the beginning of the year	**10,953**	**(13,698)**	**5,622**	**(8,076)**
Additions	1,171	(2,341)	212	(2,129)
Deductions	(835)	1,588	(349)	1,239
Currency translation differences	(1,123)	862	(202)	660
Other changes	3	(20)	(21)	(41)
Carrying amount at the end of the year	**10,169**	**(13,609)**	**5,262**	**(8,347)**

Carry-forward tax losses amounted to €19,108 million out of which €13,753 million can be used indefinitely. Carry-forward tax losses regarded Italian companies for €10,786 million and foreign companies for €8,322 million. Deferred tax assets recognized on these losses amounted to €2,615 million and €2,913 million, respectively.

Italian taxation law allows the carry-forward of tax losses indefinitely. Foreign taxation laws generally allow the carry-forward of tax losses over a period longer than five years, and in many cases, indefinitely. An average tax rate of 24% was applied to tax losses of Italian subsidiaries to determine the portion of the carry-forwards tax losses, which will be utilized in future years to offset expected taxable profit. The corresponding rate for foreign subsidiaries was 35%.

Accumulated write-down provisions of deferred tax assets related to Italian companies for €4,133 million and foreign companies for €1,608 million.

23 Derivative financial instruments

	December 31, 2018			December 31, 2017		
(€ million)	Fair value asset	Fair value liability	Level of Fair value	Fair value asset	Fair value liability	Level of Fair value
Non-hedging derivatives						
Derivatives on exchange rate						
- Currency swap	99	46	2	170	86	2
- Interest currency swap	14	71	2	41	45	2
- Outright	3	5	2	3	5	2
	116	**122**		**214**	**136**	
Derivatives on interest rate						
- Interest rate swap	18	6	2	9	5	2
	18	**6**		**9**	**5**	
Derivatives on commodities						
- Future	1,060	1,107	1	796	771	1
- Over the counter	306	284	2	81	97	2
- Other	1	5	2	1	2	2
	1,367	**1,396**		**878**	**870**	
	1,501	**1,524**		**1,101**	**1,011**	
Trading derivatives						
Derivatives on commodities						
- Over the counter	992	1,031	2	683	829	2
- Future	367	263	1	395	390	1
- Options	80	71	2	133	114	2
	1,439	**1,365**		**1,211**	**1,333**	
Cash flow hedge derivatives						
Derivatives on commodities						
- Over the counter	311	196	2	227	21	2
- Future	26	15	1	35		1
	337	**211**		**262**	**21**	
Option embedded in convertible bonds	**21**	**21**	2	**16**	**16**	2
Gross amount	**3,298**	**3,121**		**2,590**	**2,381**	
Offsetting	(1,636)	(1,636)		(1,279)	(1,279)	
Net amount	**1,662**	**1,485**		**1,311**	**1,102**	
Of which:						
- current	1,594	1,445		1,231	1,011	
- non-current	68	40		80	91	

Derivative fair values were estimated on the basis of market quotations provided by primary info-provider or, alternatively, appropriate valuation techniques generally adopted in the marketplace.

Fair values of non-hedging derivatives consisted of derivatives that did not meet the formal criteria to be designated as hedges under IFRS.

Fair values of trading derivatives consisted of derivatives entered for trading purposes and proprietary trading.

Fair value of cash flow hedge derivatives related to commodity hedges entered by the Gas & Power segment. These derivatives were entered into to hedge variability in future cash flows associated with highly probable future sale transactions of gas or electricity or on already contracted sales due to different indexation mechanism of supply costs versus selling prices. A similar scheme applies to exchange rate hedging derivatives. The effects of the measurement at fair value of cash flow hedge derivatives are given in note 25 — Shareholders' equity and in note 29 — Operating expenses. Information on hedged risks and hedging policies is disclosed in note 27 — Guarantees, commitments and risks — Risk factors.

Options embedded in convertible bonds of €21 million related to equity-linked cash settled. More information is disclosed in note 18 — Financial liabilities.

The offsetting of financial derivatives related to the Gas & Power segment.

During the 2018, there were no transfers between the different hierarchy levels of fair value.

Hedging derivative instruments are disclosed below:

	December 31, 2018		
(€ million)	**Nominal amount of the hedging instrument**	**Change in fair value (effective hedge)**	**Change in fair value (ineffective hedge)**
Cash flow hedge derivatives			
Derivatives on commodity			
- Over the counter	3,528	404	2
- Future	71	(6)	(2)
	3,599	**398**	

In 2018, the exposure to the exchange rate risk deriving from securities denominated in U.S. dollars included in the strategic liquidity portfolio amounting to €1,154 million was hedged by using, in a fair value hedge relationship, negative exchange differences for €35 million resulting on a portion of bonds denominated in U.S. dollars amounting to €1,140 million.

The breakdown of the underlying asset or liability by type of risk hedged under cash flow hedge is provided below:

	December 31, 2018		
(€ million)	**Change of the underlying asset used for the calculation of hedging ineffectiveness**	**CFH reserve**	**Reclassification adjustments**
Cash flow hedge			
Commodity price risk			
- Forecast sales	(389)	(13)	642
	(389)	**(13)**	**642**

Eni's results of operations are affected by fluctuations in the price of commodities. In order to manage commodity price risk, Eni uses derivatives traded on the organized markets MTF, OTF and derivatives traded over the counter (swaps, forward, contracts for differences and options on commodities) with the underlying commodities being crude oil, gas, refined products, electricity or emission certificates that are not settled through physical delivery of the underlying asset but are designated as hedging instruments in a cash flow hedge relation.

The existence of a relationship between hedged item and hedging instrument aimed to compensate its changes in value and the relating hedging capability not affected by the level of credit risk of the counterparty are verified for qualifying the operation as hedge.

The definition of the relationship between the quantity of the hedged item and the quantity of the hedging instrument (the so-called hedge ratio) is defined consistently with the entity's risk management objectives, under a defined risk management strategy.

The hedging relationship is discontinued when it ceases to meet the qualifying criteria and the risk management objectives on the basis of which it was qualified as for hedge accounting.

More information is reported in note 27 — Guarantees, Commitments and Risks — Risk factors.

Effects recognized in other operating profit (loss)

Other operating profit (loss) related to derivative financial instruments on commodity was as follows:

(€ million)	2018	2017	2016
Net income (loss) on cash flow hedging derivatives		12	(1)
Net income (loss) on other derivatives	129	(44)	17
	129	**(32)**	**16**

Net income (loss) on cash flow hedging derivatives related to the ineffective portion of the hedging relationship on commodity derivatives was recognized through profit and loss in the Gas & Power segment.

Net income (loss) on other derivatives included: (i) the fair value measurement and settlement of commodity derivatives which do not meet the formal criteria to be treated in accordance with hedge accounting under IFRS as they related to net exposure to commodity risk and derivatives for trading purposes and proprietary trading amounting to a net income of €129 million (net loss of €44 million in 2017 and net income of €36 million in 2016); and (ii) the fair value valuation at certain derivatives embedded in the pricing formulas of long-term gas supply contracts of the Exploration & Production segment amounting to a net loss of €19 million in 2016.

Effects recognized in finance income (loss)

Finance income (loss) on derivative financial instruments consisted of the following:

(€ million)	2018	2017	2016
Derivatives on exchange rate	(329)	809	(494)
Derivatives on interest rate	22	28	(12)
Options			24
	(307)	**837**	**(482)**

Net income from derivatives was recognized in connection with fair value valuation of certain derivatives which do not meet the formal criteria to be treated in accordance with hedge accounting under IFRS as they are entered into for amounts equal to the net exposure to exchange rate risk and interest rate risk, and as such, they cannot be referred to specific trade or financing transactions. Exchange rate derivatives were entered into in order to manage exposures to foreign currency exchange rates arising from the pricing formulas of commodities in the Gas & Power segment.

Finance income (expense) with related parties is disclosed in note 36 — Transactions with related parties.

24 Assets held for sale and liabilities directly associated with assets held for sale

As of December 31, 2018, assets held for sale and the related directly associated liabilities of €295 million and €59 million, respectively, related to: (i) Agip Oil Ecuador BV, holder of the service contract for the Villano oil field, for which a binding transfer agreement was signed. The carrying amounts of assets held for sale and directly associated liabilities amounted to €274 million (of which current assets for €81 million) and €59 million, respectively (of which current liabilities for €33 million); (ii) the sale of tangible assets and minority interests for a total carrying amount of €21 million.

In the course of 2018, Eni finalized the sale of: (i) the 98.99% (entire stake owned) of Tigáz Zrt and Tigáz DSO (100% Tigáz Zrt) to the group MET Holding AG, including Eni's gas distribution operations in Hungary; (ii) the business relating to a 26.25% stake of Lasmo Sanga Sanga Ltd (entire stake owned) of the PSA in the Sanga Sanga gas and condensates field and; (iii) the sale of a 50% (entire stake owned) interest in the joint venture Unimar Llc.

25 Shareholders' equity

As of January 1, 2018, the effects of the application of IFRS 9 and IFRS 15 are the following:

(€ million)	Share capital	Retained Earnings	Other reserves	Net profit (loss)	Total
Carrying amount at December 31, 2017	**4,005**	**35,966**	**4,685**	**3,374**	**48,030**
Changes in accounting principles (IFRS 9)		294			**294**
Changes in accounting principles (IFRS 15)		(49)			**(49)**
Carrying amount at January 1, 2018	**4,005**	**36,211**	**4,685**	**3,374**	**48,275**

More information about the application of IFRS 9 and IFRS 15 is disclosed in note 3 — Changes in accounting policies.

(€ million)	December 31, 2018	December 31, 2017
Share capital	4,005	4,005
Retained earnings	36,702	35,966
Cumulative currency translation differences	6,605	4,818
Legal reserve	959	959
Reserve for treasury shares	581	581
Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	(9)	183
Reserve related to the defined benefit plans net of tax effect	(130)	(114)
Other comprehensive income on equity-accounted investments	66	90
Other comprehensive income on other investments	15	
Other reserves	190	190
Treasury shares	(581)	(581)
Interim dividend	(1,513)	(1,441)
Net profit (loss) for the year	4,126	3,374
	51,016	**48,030**

Share capital

As of December 31, 2018, the parent company's issued share capital consisted of €4,005,358,876 represented by 3,634,185,330 ordinary shares without nominal value (same amounts as of December 31, 2017).

On May 10, 2018, Eni's Shareholders' Meeting resolved the distribution of a dividend of €0.40 per share, with the exclusion of treasury shares held at the ex-dividend date, in full settlement of the 2017 dividend of €0.40 per share, of which €0.40 per share paid as interim dividend in 2017. The balance was paid on 23 May 2018, to shareholders on the register on 21 May 2018, record date on 22 May 2018. Total dividend per share in 2017 was €0.80.

Legal reserve

This reserve represents earnings restricted from the payment of dividends pursuant to Article 2430 of the Italian Civil Code. The legal reserve has reached the maximum amount required by the Italian Law.

Reserve for treasury shares

The reserve for treasury shares represents the reserve that was established in previous reporting period to repurchase the Company shares in accordance with resolutions at Eni's Shareholders' Meetings.

Other Comprehensive Income reserves

(€ million)	Cash flow hedge derivatives Gross reserve	Deferred tax liabilities	Net reserve	Defined benefit plans Gross reserve	Deferred tax liabilities	Net reserve	Other comprehensive income on equity-accounted investments	Investments valued at fair value
Reserve as of December 31, 2017	**240**	**(57)**	**183**	**(133)**	**19**	**(114)**	**90**	
Changes of the year	399	(116)	**283**	(15)	(2)	**(17)**	(24)	15
Foreign currency translation differences				1	(1)			
Change in scope of consolidation				4	(3)	**1**		
Reversal to inventories adjustments	(10)	3	**(7)**					
Reclassification adjustments	(642)	174	**(468)**					
Reserve as of December 31, 2018	**(13)**	**4**	**(9)**	**(143)**	**13**	**(130)**	**66**	**15**
Reserve as of December 31, 2016	**246**	**(57)**	**189**	**(99)**	**(13)**	**(112)**	**21**	
Changes of the year	(59)	14	**(45)**	(33)	29	**(4)**	69	
Foreign currency translation differences				(1)	3	**2**		
Reclassification adjustments	53	(14)	**39**					
Reserve as of December 31, 2017	**240**	**(57)**	**183**	**(133)**	**19**	**(114)**	**90**	

Reserve related to investments valued at fair value does not include the effects of first application of IFRS 9 of €681 million recognized in retained earnings.

Other reserves

Other reserves related to: (i) a reserve of €127 million representing the increase in Eni shareholders' equity associated with a business combination under common control, whereby the parent company Eni SpA divested its subsidiaries; (ii) a reserve of €63 million deriving from Eni SpA's equity.

Cumulative foreign currency translation differences

The cumulative foreign currency translation differences arose from the translation of financial statements denominated in currencies other than euro.

Treasury shares

A total of 33,045,197 Eni's ordinary shares (same amount as of December 31, 2017) were held in treasury for a total cost of €581 million (same amount as of December 31, 2017). On April 13, 2017, the Shareholders Meeting approved the Long-Term Monetary Incentive Plan 2017 – 2019 and empowered the Board of Directors to execute the Plan by authorizing it to dispose up to a maximum of 11 million of treasury shares in service of the Plan.

Interim dividend

The interim dividend for the year 2018 amounted to €1,513 million corresponding to €0.42 per share, as resolved by the Board of Directors on September 13, 2018, in accordance with Article 2433-bis, paragraph 5 of the Italian Civil Code; the dividend was paid on September 26, 2018.

Distributable reserves

As of December 31, 2018, Eni shareholders' equity included distributable reserves of approximately €46 billion.

Reconciliation of net profit and shareholders' equity of the parent company Eni SpA to consolidated net profit and shareholders' equity

	Net profit		Shareholders' equity	
(€ million)	2018	2017	December 31, 2018	December 31, 2017
As recorded in Eni SpA's Financial Statements	**3,173**	**3,586**	**42,615**	**42,529**
Excess of net equity stated in the separate accounts of consolidated subsidiaries over the corresponding carrying amounts of the parent company	(134)	(466)	7,183	6,110
Consolidation adjustments:				
- difference between purchase cost and underlying carrying amounts of net equity		(1)	153	145
- adjustments to comply with Group account policies	862	202	2,000	719
- elimination of unrealized intercompany profits	177	(88)	(519)	(807)
- deferred taxation	59	144	(359)	(617)
	4,137	**3,377**	**51,073**	**48,079**
Non-controlling interest	(11)	(3)	(57)	(49)
As recorded in Consolidated Financial Statements	**4,126**	**3,374**	**51,016**	**48,030**

26 Other information

Supplemental cash flow information

(€ million)	2018	2017	2016
Investment in consolidated subsidiaries and businesses			
Current assets	44		
Non-current assets	198		
Net borrowings	11		
Current and non-current liabilities	(47)		
Net effect of investments	**206**		
Fair value of investments held before the acquisition of control	(50)		
Gain on a bargain purchase	(8)		
Purchase price	**148**		
less:			
Cash and cash equivalents	*(29)*		
Investment in consolidated subsidiaries and businesses net of cash and cash equivalent acquired	**119**		
Disposal of consolidated subsidiaries and businesses			
Current assets	328	166	6,526
Non-current assets	5,079	814	8,615
Net borrowings	785	(252)	(5,415)
Current and non-current liabilities	(3,470)	(205)	(6,334)
Net effect of disposals	**2,722**	**523**	**3,392**
Reclassification of foreign currency translation differences among other items of OCI	113		7
Fair value of share capital held after the sale of control	(3,498)		(1,006)
Fair value valuation for business combination	889		
Gain (loss) on disposal	13	2,148	11
Non-controlling interest			(1,872)
Selling price	**239**	**2,671**	**532**
less:			
Cash and cash equivalents	*(286)*	*(9)*	*(894)*
Disposal of consolidated subsidiaries and businesses net of cash and cash equivalent divested	**(47)**	**2,662**	**(362)**

Investments in 2018 concerned: (i) the acquisition of the business by Versalis Spa of the "bio" activities of Mossi & Ghisolfi Group, related to development, industrialization, licensing of bio-chemical technologies and processes based on use of renewable sources for €75 million; (ii) the acquisition of the remaining 51% stake in Gas Supply Company Thessaloniki — Thessalia SA which distributes and sells gas in Greece for €24 million, net of cash acquired of €28 million; (iii) the acquisition of the company Mestni Plinovodi distribucija plina doo, which distributes and sells gas in Slovenia for €15 million, net of cash acquired for €1 million. The gain from bargain purchase, recognized in Other income and revenues, was due to the obtainable synergies from the greater ability to recover the investments made by the acquired company due to the combination of customer portfolios.

Disposals in 2018 concerned: (i) the loss of control of Eni Norge AS resulting from the business combination with Point Resources AS, with the establishment of the equity-accounted joint venture Vår Energi AS (Eni interest 69.60%), that will develop the project portfolio of the combined entities. The operation entailed the exclusion from the consolidation area of €2,486 million of net assets, of which cash and cash equivalents for €258 million, the recognition of the investment in Vår Energi AS for €3,498 million and a fair value gain of €889 million, net of negative exchange rate differences of €123 million; (ii) the sale of 98.99% (entire stake owned) of Tigáz Zrt and Tigáz Dso (100% Tigáz Zrt) operating in the gas distribution business in Hungary to the MET Holding AG group for €145 million net of cash divested of €13 million; (iii) the sale by Lasmo Sanga Sanga of the business relating to a 26.25% stake (entire stake owned) in the PSA of the Sanga Sanga gas and condensates field for €33 million; (iv) the sale of 100% of Eni Croatia BV, which owns shares of gas projects in Croatia to INA-Industrija Nafte dd for €20 million, net of cash divested of €15 million; (v) the sale of 100% of Eni Trinidad and Tobago Ltd, which holds a share of a gas project in Trinidad & Tobago for €10 million.

27 Guarantees, commitments and risks

Guarantees

(€ million)	December 31, 2018	December 31, 2017
Consolidated subsidiaries	5,082	5,595
Unconsolidated subsidiaries	196	181
Joint ventures and associates	4,056	10,046
Others	163	352
	9,497	**16,174**

The parent company of the Eni Group issued guarantees to cover the contractual obligations held by third parties towards Eni's affiliates to build and finance the construction of an LNG Floating Production unit for the development of the Coral gas reserves discovered in Area 4 offshore Mozambique. The value of the contract is €4,586 million. Eni is operator of the project with a 25% indirect interest through a 35.71% stake in the joint operation Mozambique Rovuma Venture SpA. The final investment decision (FID) for the Coral project was made on June 1, 2017. The FLNG plant is designed to treat approximately 3.37 million tonnes per year of LNG. A special purpose entity was established, Coral FLNG SA (Eni's interest 25%). This entity will operate the vessel in accordance to a service agreement for the liquefaction, storage and loading of the LNG on behalf of the Concessionaires of Area 4 and of the other two partners of Mozambique Rovuma Venture SpA, CNPC and ExxonMobil in proportion to their participating interest in the Exploration and Production Concession Contract (EPCC) of Area 4, equal to 20% and 25%, respectively. The LNG will be supplied to BP under a long-term LNG sale and purchase agreement with a take-or-pay clause and a twenty-year term, providing an option of extending the duration for up to ten consecutive years. Eni issued through a subsidiary a parent company guarantee, whereby it irrevocably and unconditionally guarantees the Technip — JGC — Samsung Heavy Industries (TJS) consortium (the beneficiaries) for the due and proper performance of the obligations of Coral FLNG SA in connection with execution of the Engineering Procurement Construction Installation and Commissioning (EPCIC) contract, up to the maximum liability of €1,147 million equal to 25% of the value of the contract. The maximum liability will be automatically reduced by any amount paid to the beneficiaries in respect of the guaranteed obligations. The financing of the project is carried out partly through funds provided by the venturers and partly by a project financing with Export Credit Agencies and commercial banks for a total amount of €4,082 million. During the construction and the commissioning of the FLNG plant, the project financing agreement will be supported by a debt service undertaking, up to a maximum liability of €1,397 million in proportion to Eni's participating interest equal to 25% in the industrial initiative. Subsequently, in the running phase of the plant, once the performance tests of the vessel have been validated by the lenders, that guarantee will be released and the financing facility will change into a non-recourse one, terminating the obligations of the venturers of Area 4. Once vessel operations start, the lenders will be guaranteed only by the vessel cash flows, excluding the gas reserves from the scope of the guarantee. The financing and any collateral costs will be reimbursed to the lenders through a "pay-when-paid" clause, whereby loan repayments will be made through the cash flows associated with the sale of the LNG arising from the project to the long-term buyer, without any obligations from Eni and Concessionaires to guarantee the performance of Coral FLNG SA towards the lenders. Furthermore, the Concessionaries opened a credit facility which committed each Concessionary to finance pro-quota: (i) the share of capital expenditures to be borne by the Mozambique State-owned company ENH up to a maximum liability of €121 million in Eni's share; (ii) the share of the debt service undertaking by ENH up to a maximum liability of €155 million in Eni's share. As a final point, as provided by the EPCC that regulates the petroleum activities in Area 4, Eni SpA in its capacity as parent company of the operator Mozambique Rovuma Venture SpA has provided concurrently with the approval of the initial development plan of the Area reserves, an irrevocable and unconditional parent company guarantee in respect of any possible claims or any contractual breaches in connection with the petroleum activities to be carried out in the contractual area, including those activities in charge of the special purpose entities like Coral FLNG SA, to benefit of the Government of Mozambique and third parties. The obligations of the guarantor towards the Government of Mozambique are unlimited (non-quantifiable commitments), whereas they provide a maximum liability of €1,309 million in respect of third-parties claims. This guarantee will be effective until the completion of any decommissioning activity related to both the development plan of Coral as well as any development plan to be executed within Area 4 (particularly the Mamba project). This parent company guarantee issued by Eni covering 100% of the aforementioned obligations was taken over by the other concessionaires (Kogas, Galp and ENH) and by ExxonMobil and CNPC shareholders of the joint operation Mozambico Rovuma Venture SpA, in proportion to their respective participating interest in the EPCIC of Area 4.

Guarantees issued on behalf of consolidated subsidiaries primarily consisted of: (i) guarantees given to third parties relating to bid bonds and performance bonds for €2,576 million (€2,312 million at December 31, 2017); (ii) a bank guarantee of €1,010 million (same amount as of December 31, 2017) issued on behalf of GasTerra in order to obtain the renunciation to a temporary seizure order on Eni's investment in Eni International BV, requested and obtained by a Netherlands Court in July 2016. At December 31, 2018, the underlying commitment covered by such guarantees was €5,000 million (€5,564 million at December 31, 2017).

Guarantees issued on behalf of joint ventures and associates primarily consisted of: (i) an unsecured guarantee of €499 million (€6,122 million at December 31, 2017) given by Eni SpA to Treno Alta Velocità — TAV SpA (now RFI — Rete Ferroviaria Italiana SpA) for the proper and timely completion of a project relating to the Milan-Bologna fast track railway by CEPAV (Consorzio Eni per l'Alta Velocità) Uno (associated company of Saipem); the decrease of €5,623 million is due to the cancellation of the guarantees related to the completion of the main lots of the project; (ii) unsecured guarantees and other guarantees given to banks in relation to loans and lines of credit received for €1,664 million (€1,623 million at December 31, 2017), of which €1,397 million (€1,334 million at December 31, 2017) related to guarantees issued as part of the development project of the gas reserves at the Coral discovery in Area 4 offshore Mozambique on behalf of Coral South FLNG DMCC with respect to the financing agreements of the project with Export Credit Agencies and banks; and (iii) guarantees given to third parties relating to bid bonds and performance bonds for €1,644 million (€2,122 at December 31, 2017), of which €1,147 million (€1,094 million at December 31, 2017) related to guarantees issued for the construction of the FLNG as part of the development project of the gas reserves at the Coral project offshore Mozambique and €279 million given on behalf of Saipem Group (€1,008 million at December 31, 2017); (iv) a guarantee issued in favor of Gulf LNG Energy and Gulf LNG Pipeline and on behalf of Angola LNG Supply Service Llc (Eni's interest 13.60%) as security against payment commitments of fees in connection with the regasification activity for €177 million (€169 million at December 31, 2017). At December 31, 2018, the underlying commitment covered by such guarantees was €2,159 million (€2,594 million at December 31, 2017).

Commitments and risks

(€ million)	December 31, 2018	December 31, 2017
Commitments	54,611	14,498
Risks	673	691
	55,284	**15,189**

Commitments related to: (i) parent company guarantees that were issued in connection with certain contractual commitments for hydrocarbon exploration and production activities and quantified, on the basis of the capital expenditures to be incurred, to €52,397 million (€11,289 million at December 31, 2017).

The increase of €41,108 million essentially related to: (a) the issue of parent company guarantees, in relation to transactions with the Abu Dhabi State oil company, ADNOC, whereby Eni acquired participating interests in the two offshore concessions in production of Lower Zakum (Eni's interest 5%) and Umm Shaif and Nasr (Eni's interest 10%) for a period of 40 years and a maximum amount of €13,094 million and in the concession under development of Gasha (Eni's interest 25%) for a period of 40 years and a maximum amount of €21,824 million. These guarantees were issued to cover the contractual obligations towards the State company, deriving from oil operations related to the Concession Agreements including, in particular, the achievement of some production targets and recovery factors of reserves in the medium and long term, an asset integrity plan and optimization and maintenance of the production after reaching the plateau, the transfer of technologies and the adoption of best-in-class operating standards in HSE. The guarantees do not cover any loss of profit or production deriving from failure to achieve the targets; (b) the issue of parent company guarantees for €6,831 million following the awarding of new exploration licenses in the offshore of Mexico and the final investment decision for the development of the offshore reserves in Area 1; (ii) commitments assumed by Eni USA Gas Marketing Llc towards Angola LNG Supply Service Llc for the purchase of volumes of regasified gas at the Pascagoula plant (United States) over a twenty-year period (until 2031). The expected commitments were estimated at €2,079 million (€2,113 million at December 31, 2017) and included in off-balance sheet contractual commitments in the table "Future payments under contractual obligations" in the paragraph *Liquidity risk*. In 2018, the contractual commitment signed in December 2007 between Eni USA Gas Marketing Llc and Gulf LNG Energy Llc (GLE) and Gulf LNG Pipeline Llc (GLP) for the supply of long-term regasification and import services (until 2031) amounting at the opening balance to €948 million (undiscounted) ceased due to an arbitration award, ruling that the commitment was resolved by March 1, 2016 and recognizing to the counterparties an equitable compensation of €324 million, accounted as expense in the income statement. Despite the ruling of the arbitration court invalidating the contract, GLE and GLP filed a claim with the Supreme Court of New York against Eni SpA demanding the enforcement of the parent company guarantee issued by Eni for the payment of the regasification fees until to the original due date of the contract (2031) for a maximum amount of €757 million. Eni believes that the claims by GLE and GLP have no merit and is defending the action. At the moment, the risk of losing the proceeding is considered unlikely; (iii) a memorandum of intent signed with the Basilicata Region, whereby Eni has agreed to invest €116 million (€128 million at December 31, 2017) in the future, also on account of Shell Italia E&P SpA, in connection with Eni's development plan of oilfields in Val d'Agri. The commitment has been included in the off-balance sheet contractual commitments in the following paragraph "Liquidity risk".

Risks concerned potential risks associated with contractual assurances given to acquirers of certain investments and businesses of Eni for €244 million (€235 million at December 31, 2017) and the value of assets of third parties under the custody of Eni for €429 million (€456 million at December 31, 2017).

Non-quantifiable commitments

A parent company guarantee was issued on behalf of Cardón IV SA (Eni's interest 50%), a joint venture that is currently operating the Perla gas field located in Venezuela, for the supplying to PDVSA GAS of the volumes of gas produced by the field until end of the concession agreement (2036). This guarantee cannot be quantified because the penalty clause for unilateral anticipated resolution originally set for Eni and the relevant quantification became ineffective due to a revision of the contractual terms. In case of failure on part of the operator to deliver the contractual gas volumes out of production, the claim under the guarantee will be determined by applying the local legislation. Eni share (50%) of the contractual volumes of gas to be delivered to PDVSA GAS amounted to a total of €13 billion. Notwithstanding this amount does not properly represent the guarantee exposure, nonetheless such amount represents the maximum financial exposure at risk for Eni. A similar guarantee was issued by PDVSA on behalf of Eni for the fulfillment of the purchase commitments of the gas volumes by PDVSA GAS.

Eni is liable for certain non-quantifiable risks related to contractual assurances given to acquirers of certain Eni assets, including businesses and investments, against certain contingent liabilities deriving from tax, social security contributions, environmental issues and other matters applicable to periods during which such assets were operated by Eni. Eni believes such matters will not have a material adverse effect on Eni's results of operations and liquidity.

Risk factors

Financial risks

Financial risks are managed in respect of guidelines issued by the Board of Directors of Eni SpA in its role of directing and setting of the risk limits, targeting to align and centrally coordinate Group companies' policies on financial risks ("Guidelines on financial risks management and control"). The "Guidelines" define for each financial risk the key components of the management and control process, such as the aim of the risk management, the valuation methodology, the structure of limits, the relation model and the hedging and mitigation instruments.

Market risk

Market risk is the possibility that changes in currency exchange rates, interest rates or commodity prices will adversely affect the value of the Group's financial assets, liabilities or expected future cash flows. The Company actively manages market risk in accordance with a set of policies and guidelines that provide a centralized model of handling finance, treasury and risk management operations based on the Company's departments of operational finance: the parent company's (Eni SpA) finance department, Eni Finance International SA, Eni Finance USA Inc and Banque Eni SA, which is subject to certain bank regulatory restrictions preventing the Group's exposure to concentrations of credit risk, and Eni Trading & Shipping that is in charge to execute certain activities relating to commodity derivatives. In particular, Eni's finance department and Eni Finance International SA manage subsidiaries' financing requirements in and outside Italy, respectively, covering funding requirements and using available surpluses. All transactions concerning currencies and derivative contracts on interest rates and currencies different from commodities are managed by the parent company, while Eni Trading & Shipping SpA executes the negotiation of commodity derivatives over the market. Eni SpA and Eni Trading & Shipping SpA (also through its subsidiary Eni Trading & Shipping Inc) perform trading activities in financial derivatives on external trading venues, such as European and non-European regulated markets, Multilateral Trading Facility (MTF), Organized Trading Facility (OTF), or similar and brokerage platforms (i.e. SEF), and over the counter on a bilateral basis with external counterparties. Other legal entities belonging to Eni that require financial derivatives enter into these operations through Eni Trading & Shipping and Eni SpA based on the relevant asset class expertise. Eni uses derivative financial instruments (derivatives) in order to minimize exposure to market risks related to fluctuations in exchange rates relating to those transactions denominated in a currency other than the functional currency (the euro) and interest rates, as well as to optimize exposure to commodity prices fluctuations taking into account the currency in which commodities are quoted. Eni monitors every activity in derivatives classified as risk-reducing (in particular, back-to-back activities, flow hedging activities, asset-backed hedging activities and portfolio-management activities) directly or indirectly related to covered industrial assets, so as to effectively optimize the risk profile to which Eni is exposed or could be exposed. If the result of the monitoring shows those derivatives should not be considered as risk reducing, these derivatives are reclassified in proprietary trading. As the proprietary trading is considered separately from the other activities in specific portfolios of Eni Trading & Shipping, its exposure is subject to specific controls, both in terms of Value at Risk (VaR) and stop loss and in terms of nominal gross value. For Eni, the gross nominal value of proprietary trading activities is compared with the limits set by the relevant international standards. The framework defined by Eni's policies and guidelines provides that the valuation and control of market risk is performed on the basis of maximum tolerable levels of risk exposure defined in terms of: (i) limits of stop loss, which expresses the maximum tolerable amount of losses associated with a certain portfolio of assets over a pre-defined time horizon; (ii) limits of revision strategy, which consist in the triggering of a revision process of the strategy in the event of exceeding the level of profit and loss given; and (iii) VaR which measures the maximum potential loss of the portfolio, given a certain confidence level and holding period, assuming adverse changes in market variables and taking into account of the correlation among the different positions held in the portfolio. Eni's finance department defines the maximum tolerable levels of risk exposure to changes in interest rates and foreign currency exchange rates in terms of VaR, pooling Group companies' risk positions maximizing, when possible, the benefits of the netting activity. Eni's calculation and valuation techniques for interest rate and foreign currency exchange rate risks are in accordance with banking standards, as established by the Basel Committee for bank activities surveillance. Tolerable levels of risk are based on a conservative approach, considering the industrial nature of the Company. Eni's guidelines prescribe that Eni Group companies minimize such kinds of market risks by transferring risk exposure to the parent company finance department. Eni's guidelines define rules to manage the commodity risk aiming at optimizing core activities and pursuing preset targets of stabilizing industrial and commercial margins. The maximum tolerable level of risk exposure is defined in terms of VaR, limits of revision strategy, stop loss and volumes in connection with exposure deriving from commercial activities, as well as exposure deriving from proprietary trading, exclusively managed by Eni Trading & Shipping. Internal mandates to manage the commodity risk provide for a mechanism of allocation of the Group maximum tolerable risk level to each business unit. In this framework, Eni Trading & Shipping, in addition to managing risk exposure associated with its own commercial activity and proprietary trading, pools the requests for negotiating commodity derivatives and executes them on the marketplace.

According to the targets of financial structure included in the financial plan approved by the Board of Directors, Eni has decided to retain a cash reserve to face any extraordinary requirement. Eni's finance department, with the aim of optimizing the efficiency and ensuring maximum protection of the capital, manages such reserve and its immediate liquidity within the limits assigned. The management of strategic cash is part of the asset management pursued through transactions on own risk in view of optimizing financial returns, while respecting authorized risk levels, safeguarding the Company's assets and retaining quick access to liquidity.

The four different market risks, whose management and control have been summarized above, are described below.

Market risk — Exchange rate

Exchange rate risk derives from the fact that Eni's operations are conducted in currencies other than the euro (mainly the U.S. dollar). Revenues and expenses denominated in foreign currencies may be significantly affected by exchange rates fluctuations due to conversion differences on single transactions arising from the time lag existing between execution and definition of relevant contractual terms (economic risk) and conversion of foreign currency-denominated trade and financing payables and receivables (transactional risk). Exchange rate fluctuations affect the Group's reported results and net equity as financial statements of subsidiaries denominated in currencies other than the euro are translated from their functional currency into euro. Generally, an appreciation of the U.S. dollar versus the euro has a positive impact on Eni's results of operations, and vice versa. Eni's foreign exchange risk management policy is to minimize transactional exposures arising from foreign currency movements and to optimize exposures arising from commodity risk. Eni does not undertake any hedging activity for risks deriving from the translation of foreign currency denominated profits or assets and liabilities of subsidiaries, which prepare financial statements in a currency other than the euro, except for single transactions to be evaluated on a case-by-case basis. Effective management of exchange rate risk is performed within Eni's central finance department, which pools Group companies' positions, hedging the Group net exposure by using certain derivatives, such as currency swaps, forwards and options. Such derivatives are evaluated at fair value based on market prices provided by specialized info-providers. Changes in fair value of those derivatives are normally recognized through profit and loss, as they do not meet the formal criteria to be recognized as hedges. The VaR techniques are based on variance/covariance simulation models and are used to monitor the risk exposure arising from possible future changes in market values over a 24-hour period within a 99% confidence level and a 20-day holding period.

Market risk — Interest rate

Changes in interest rates affect the market value of financial assets and liabilities of the Company and the level of finance charges. Eni's interest rate risk management policy is to minimize risk with the aim to achieve financial structure objectives defined and approved in the management's finance plans. The Group's central finance department pools borrowing requirements of the Group companies in order to manage net positions and fund portfolio developments consistent with management plans, thereby maintaining a level of risk exposure within prescribed limits. Eni enters into interest rate derivative transactions, in particular interest rate swaps, to manage effectively the balance between fixed and floating rate debt. Such derivatives are evaluated at fair value based on market prices provided from specialized sources. Changes in fair value of those derivatives are normally recognized through the profit and loss account, as they do not meet the formal criteria to be accounted for under the hedge accounting method. VaR deriving from interest rate exposure is measured daily based on a variance/covariance model, with a 99% confidence level and a 20-day holding period.

Market risk — Commodity

Eni's results of operations are affected by changes in the prices of commodities. A decrease in oil&gas prices generally, has a negative impact on Eni's results of operations and vice versa, and may jeopardize the achievement of the financial targets preset in the Company's four-year plans and budget. The commodity price risk arises in connection with the following exposures: (i) strategic exposure: exposures directly identified by the Board of Directors as a result of strategic investment decisions or outside the planning horizon of risk. These exposures include those associated with the program for the production of proved and unproved oil&gas reserves, long-term gas supply contracts for the portion not balanced by ongoing or highly probable sale contracts, refining margins identified by the Board of Directors as of strategic nature (the remaining volumes can be allocated to the active management of the margin or to asset-backed hedging activities) and minimum compulsory stocks; (ii) commercial exposure: includes the exposures related to the components underlying the contractual arrangements of industrial and commercial activities and, if related to take-or-pay commitments, to the components related to the time horizon of the four-year plan and budget and the relevant activities of risk management. Commercial exposures are characterized by a systematic risk management activity conducted based on risk/return assumptions by implementing one or more strategies and subjected to specific risk limits (VaR, revision strategy limits and stop loss). In particular, the commercial exposures include exposures subjected to asset-backed hedging activities, arising from the flexibility/optionality of assets; and (iii) proprietary trading exposure: includes operations independently conducted for profit purposes in the short term, and normally not finalized to the delivery, both within the commodity and financial markets, with the aim to obtain a profit upon the occurrence of a favorable result in the market, in accordance with specific limits of authorized risk (VaR, stop loss). In the proprietary trading exposures are included the origination activities, if not connected to contractual or physical assets.

Strategic risk is not subject to systematic activity of management/coverage that is eventually carried out only in case of specific market or business conditions. Because of the extraordinary nature, hedging activities related to strategic risks are delegated to the top management. Strategic risk is subject to measuring and monitoring but is not subject to specific risk limits. If previously authorized by the Board of Directors, exposures related to strategic risk can be used in combination with other commercial exposures in order to exploit opportunities for natural compensation between the risks (natural hedge) and consequently reduce the use of derivatives (by activating logics of internal market). Eni manages exposure to commodity price risk arising in normal trading and commercial activities in view of achieving stable economic results. Eni manages the commodity risk and the exposure to commodity prices through the trading unit of Eni Trading & Shipping by using derivatives traded on the organized markets MTF, OTF and derivatives traded over the counter (swaps, forward, contracts for differences and options on commodities) with the underlying commodities being crude oil, gas, refined products, electricity or emission certificates. Such derivatives are evaluated at fair value based on market prices provided from specialized sources or, absent market prices, on the basis of estimates provided by brokers or suitable valuation techniques. VaR deriving from commodity exposure is measured daily based on a historical simulation technique, with a 95% confidence level and a one-day holding period.

Market risk — Strategic liquidity

Market risk deriving from liquidity management is identified as the possibility that changes in prices of financial instruments (bonds, money market instruments and mutual funds) would affect the value of these instruments when evaluated at fair value. The setting up and maintenance of the liquidity reserve is mainly aimed to guarantee a proper financial flexibility. Liquidity should allow Eni Group to fund any extraordinary need (such as difficulty in access to credit, exogenous shock, macroeconomic environment, as well as merger and acquisitions) and must be dimensioned to provide a coverage of short-term debts and a coverage of medium and long-term financial debts due within a time horizon of 24 months. In order to manage the investment activity of the strategic liquidity, Eni defined a specific investment policy with aims and constraints in terms of financial activities and operational boundaries, as well as Governance guidelines regulating management and control systems. In particular, strategic liquidity management is regulated in terms of VaR (measured based on a parametrical methodology with a one-day holding period and a 99% confidence level), stop loss and other operating limits in terms of concentration, issuing entity, business segment, country of emission, duration, ratings and type of investing instruments in portfolio, aimed to minimize market and liquidity risks. Financial leverage or short selling is not allowed. Activities in terms of strategic liquidity management started in the second half of the year 2013 (portfolio Euro) and throughout the course of the years 2017 (portfolio USD). In 2018, the investment portfolio Euro has maintained an average credit rating of A-/BBB+, the investment portfolio USD has maintained an average credit rating of A+/A, both in line with the year 2017.

The following table shows amounts in terms of VaR, recorded in 2018 (compared with 2017) relating to interest rate and exchange rate risks in the first section and commodity risk. Regarding the management of strategic liquidity, the sensitivity to changes of interest rate is expressed by values of "Dollar value per Basis Point" (DVBP).

(Value at risk — parametric method variance/covariance; holding period: 20 days; confidence level: 99%)

	2018				2017			
(€ million)	**High**	**Low**	**Average**	**At year end**	**High**	**Low**	**Average**	**At year end**
Interest rate[(a)]	3.65	1.80	2.73	2.99	3.76	1.72	2.38	2.58
Exchange rate[(a)]	0.57	0.09	0.28	0.25	0.57	0.08	0.22	0.26

(a) Value at risk deriving from interest and exchange rates exposures include the following finance department: Eni Corporate Treasury Department, Eni Finance International SA, Banque Eni SA and Eni Finance USA Inc.

(Value at risk — Historic simulation weighted method; holding period: 1 day; confidence level: 95%)

	2018				2017			
(€ million)	**High**	**Low**	**Average**	**At year end**	**High**	**Low**	**Average**	**At year end**
Commercial exposures								
– Management Portfolio[(a)]	18.60	6.79	11.04	7.50	21.14	5.15	12.24	5.15
Trading [(b)]	2.28	0.26	0.73	0.27	2.29	0.21	0.79	0.66

(a) Refers to the Gas & LNG Marketing Power business line (risk exposure from Refining & Marketing business line and Gas & Power Division), Eni Trading & Shipping commercial portfolio, operating branches outside Italy pertaining to the Divisions and from October 2016 the Gas and Luce Business line. For the gas&power business lines, following the approval of the Eni's Board of Directors on December 12, 2013, VaR is calculated on the so-called Statutory view, with a time horizon that coincides with the year considering all the volumes delivered in the year and the relevant financial hedging derivatives. Consequently, in the year the VaR pertaining to GLP and EGL presents a decreasing trend following the progressive reaching of the maturity of the positions within the annual horizon.

(b) Cross-commodity proprietary trading, both for commodity contracts and financial derivatives, refers to Eni Trading & Shipping SpA (London-Bruxelles-Singapore) and Eni Trading & Shipping Inc (Houston).

(Sensitivity — Dollar value of 1 basis point — DVBP)

	2018				2017			
(€ million)	**High**	**Low**	**Average**	**At year end**	**High**	**Low**	**Average**	**At year end**
Strategic liquidity[(a)]	0.35	0.25	0.29	0.25	0.41	0.27	0.35	0.27

(a) Management of strategic liquidity portfolio starting from July 2013.

(Sensitivity — Dollar value of 1 basis point — DVBP)

	2018				2017			
($ million)	High	Low	Average	At year end	High	Low	Average	At year end
Strategic liquidity[(b)]	0.04	0.01	0.02	0.02	0.04	0.02	0.03	0.03

(b) Management of strategic liquidity portfolio in $currency starting from August 2017.

Credit risk

Credit risk is the potential exposure of the Group to losses in case counterparties fail to perform or pay amounts due. Eni defined credit risk management policies consistent with the nature and characteristics of the counterparties of commercial and financial transactions and with regard to the latter, among of the others, of the centralized finance model adopted.

The Company adopted a model to quantify and control the credit risk based on the evaluation of the expected loss for which the probability of default and the capacity to recover credits in default is estimated through the so-called Loss Given Default.

In the credit risk management and control model, credit exposures are distinguished by commercial nature, substantially in relation to the structured contracts on commodities related to Eni's core business, and by financial nature, substantially in relation to the financial instruments used by Eni, such as deposits, derivatives and securities.

Credit risk for commercial exposures

Credit risk arising from commercial counterparties is managed by the business units and by the specialized corporate finance and administration departments, and is operated on the basis of formal procedures for the assessment and assignment of commercial counterparties, the monitoring of credit exposures, credit recovery activities and disputes. At corporate level, the general guidelines and methods for quantifying and controlling customer risk, in particular for commercial counterparties, are assessed through an internal rating model that combines different default factors deriving from economic variables, financial indicators, payment experiences and information from primary info providers. The probability of default related to State Entities or their closely related counterparties (eg National Oil Company), essentially represented by the probability of late payments, is determined by using the country risk premiums adopted for the purposes of the determination of the WACCs for the impairment of non-financial assets. Furthermore, for retail positions without specific ratings, the risk is determined by distinguishing customers in homogeneous risk clusters based on historical series of data relating to payments made, periodically updated.

Credit risk for financial exposures

With regard to credit risk arising from financial counterparties deriving from current and strategic use of liquidity, derivative contracts and transactions with underlying financial assets valued at fair value, Eni has established internal policies providing exposure control and concentration through maximum credit risk limits corresponding to different classes of financial counterparties as defined by the Company's Board of Directors taking into account the credit ratings provided by primary credit rating agencies on the marketplace. Credit risk arising from financial counterparties is managed by the Group operating finance department, including Eni's subsidiary Eni Trading & Shipping which specifically engages in commodity derivatives transactions and by Group companies and Divisions, only in the case of physical transactions with financial counterparties consistently with the Group centralized finance model. Eligible financial counterparties are closely monitored by each counterpart and by group of belonging to check exposures against the limits assigned on a daily basis and the expected loss analysis and the concentration periodically.

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the Group may not be available, or the Group is unable to sell its assets on the marketplace in order to meet short-term finance requirements and to settle obligations. Such a situation would negatively affect Group results, as it would result in the Company incurring higher borrowing expenses to meet its obligations or under the worst of conditions the inability of the Company to continue as a going concern. Eni's risk management targets include the maintaining of an adequate level of liquidity readily available to deal with external shocks (drastic changes in the scenario, restrictions on access to capital markets, etc.) or to ensure an adequate level of operational flexibility for the development programs of the Company. The strategic liquidity reserve is employed in short-term marketable financial instruments, favouring investments with very low risk profile.

At present, the Group believes to have access to sufficient funding to meet the current foreseeable borrowing requirements as a consequence of the availability of financial assets and lines of credit and the access to a wide range of funding at competitive costs through the credit system and capital markets.

Eni has in place a program for the issuance of Euro Medium Term Notes up to €20 billion, of which about €16.7 billion were drawn as of December 31, 2018.

The Group has credit ratings of A- outlook stable and A-2, respectively for long and short-term debt, assigned by Standard & Poor's and Baa1 outlook stable and P-2, respectively for long and short-term debt, assigned by Moody's. Eni's credit rating is linked in addition to the Company's industrial fundamentals and trends in the trading environment to the sovereign credit rating of Italy. Based on the methodologies used by Standard & Poor's and Moody's, a downgrade of Italy's credit rating may trigger a potential knock-on effect on the credit rating of Italian issuers such as Eni. During 2018, Moody's reduced the rating of Eni by one notch (from A3 to Baa1) following the reduction in the rating assigned to Italy (from Baa2 to Baa3, outlook stable).

In the course of the 2018, Eni issued bonds amounting to €2.8 billion, of which €1.1 billion were issued under the Euro Medium Term Notes program and €1.7 billion through a dual-tranche issue on the U.S. market and on international markets.

As of December 31, 2018, Eni maintained short-term unused borrowing facilities of €12,484 million. Long-term committed unused borrowing facilities amounted to €5,214 million due beyond 12 months. These facilities bore interest rates and fees for unused facilities that reflected prevailing market conditions.

Finance debt repayments including expected payments for interest charges and derivatives

The table below summarizes the Group main contractual obligations for finance liability repayments, including expected payments for interest charges and derivatives.

	Maturity year						
(€ million)	2019	2020	2021	2022	2023	2024 and thereafter	Total
December 31, 2018							
Non-current financial liabilities (including the current portion)	3,301	2,958	1,541	1,253	2,714	11,723	**23,490**
Current financial liabilities	2,182						**2,182**
Fair value of derivative instruments	1,445	13	1	21		5	**1,485**
	6,928	**2,971**	**1,542**	**1,274**	**2,714**	**11,728**	**27,157**
Interest on finance debt	655	545	436	330	320	1,677	**3,963**
Financial guarantees	668						**668**

	Maturity year						
(€ million)	2018	2019	2020	2021	2022	2023 and thereafter	Total
December 31, 2017							
Non-current financial liabilities (including the current portion)	2,000	4,084	2,857	1,279	1,246	10,810	**22,276**
Current financial liabilities	2,242						**2,242**
Fair value of derivative instruments	1,011	64	10	1	16		**1,102**
	5,253	**4,148**	**2,867**	**1,280**	**1,262**	**10,810**	**25,620**
Interest on finance debt	582	511	411	304	250	1,455	**3,513**
Financial guarantees	473						**473**

Trade and other payables

The table below summarizes the Group trade and other payables by maturity.

(€ million)	Maturity year 2019	2020 – 2023	2024 and thereafter	Total
December 31, 2018				
Trade payables	11,645			11,645
Other payables and advances	5,102	59	96	5,257
	16,747	**59**	**96**	**16,902**

(€ million)	Maturity year 2018	2019 – 2022	2023 and thereafter	Total
December 31, 2017				
Trade payables	10,890			10,890
Other payables and advances	5,858	19	26	5,903
	16,748	**19**	**26**	**16,793**

Expected payments by period under contractual obligations

In addition to trade and financial liabilities represented in the balance sheet, the company is subject to non-cancellable contractual obligations or obligations, the cancellation of which requires the payment of a penalty. These obligations will require cash settlements in future reporting periods. These liabilities are valued based on the net cost for the company to fulfill the contract, which consists of the lowest amount between the costs for the fulfillment of the contractual obligation and the contractual compensation/penalty in the event of the non-performance.

The Company's main contractual obligations at the balance sheet date comprise: (i) take-or-pay clauses contained in the Company's gas supply contracts or shipping arrangements, whereby the Company obligations consist of off-taking minimum quantities of product or service or, in case of failure, paying the corresponding cash amount that entitles the Company the right to collect the product or the service in future years. Future obligations in connection with these contracts were calculated by applying the forecasted prices of energy or services included in the four-year business plan approved by the Company's Board of Directors; (ii) operating leases for tangible assets, of which primarily for FPSO units of the E&P segment, in particular FPSOs operating in the offshore projects at Cape Three Points in Ghana and at the 15/06 block in Angola, with a duration of between 11 and 14 years.

The table below summarizes the Group principal contractual obligations as of the balance sheet date, shown on an undiscounted basis.

	Maturity year						
(€ million)	2019	2020	2021	2022	2023	2024 and thereafter	Total
Operating lease obligations[(a)]	**776**	**601**	**481**	**303**	**268**	**1,524**	**3,953**
Decommissioning liabilities[(b)]	**335**	**294**	**407**	**260**	**124**	**12,394**	**13,814**
Environmental liabilities	**349**	**321**	**254**	**239**	**188**	**1,245**	**2,596**
Purchase obligations[(c)]	**14,674**	**11,258**	**10,649**	**9,683**	**9,546**	**76,014**	**131,824**
- Gas							
- take-or-pay contracts	11,886	10,470	9,995	9,276	9,210	75,035	125,872
- ship-or-pay contracts	1,164	558	482	382	324	941	3,851
- Other purchase obligations	1,624	230	172	25	12	38	2,101
Other obligations	**8**	**1**	**1**	**1**	**1**	**104**	**116**
- Memorandum of intent Val d'Agri	8	1	1	1	1	104	116
	16,142	**12,475**	**11,792**	**10,486**	**10,127**	**91,281**	**152,303**

(a) There are no significant restrictions provided by these operating leases which limit the ability of the Company to pay dividend, use assets or to take on new borrowings.

(b) Represents the estimated future costs for the decommissioning of oil and natural gas production facilities at the end of the producing lives of fields, well-plugging, abandonment and site restoration.

(c) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms.

Capital investment and capital expenditure commitments

In the next four years, Eni expects capital investments and capital expenditures of €32.7 billion. The table below summarizes Eni's capital expenditure commitments for property, plant and equipment and capital projects. Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. At this stage, procurement contracts to execute those projects have already been awarded or are being awarded to third parties.

The amounts shown in the table below include committed expenditures to execute certain environmental projects.

	Maturity year					
(€ million)	2019	2020	2021	2022	2023 and thereafter	Total
Committed projects	6,492	4,917	3,458	1,910	3,629	**20,406**

Other information about financial instruments

The carrying amount of financial instruments and the relevant economic and equity effect consisted of the following:

(€ million)	2018 Carrying amount	2018 Finance income (expense) recognized in Profit and loss account	2018 Finance income (expense) recognized in Other comprehensive income	2017 Carrying amount	2017 Finance income (expense) recognized in Profit and loss account	2017 Finance income (expense) recognized in Other comprehensive income
Held-for-trading financial instruments						
Financial assets held for trading[a]	6,552	32		6,012	(111)	
Non-hedging and trading derivatives[b]	117	(178)		209	793	
Non-current financial instruments						
Held-to-maturity securities[a]				73		
Available-for-sale financial instruments						
Securities[a]				207	9	(4)
Other investments valued at fair value[c]	919	231	15			
Receivables and payables and other assets/ liabilities valued at amortized cost:						
Trade receivables and other[d]	14,145	(343)		15,583	(958)	
Financing receivables[e]	1,489	(139)		1,918	(116)	
Securities[a]	64					
Trade payables and other[a]	16,902	(28)		16,793	(51)	
Financing payables[f]	25,865	(615)		24,707	(1,137)	
Net assets (liabilities) for hedging derivatives[g]		**642**	**(243)**		**(42)**	**(6)**

(a) Income or expense were recognized in the profit and loss account within "Finance income (expense)".

(b) In the profit and loss account, economic effects were recognized as income within "Other operating income (loss)" for €129 million (loss for €44 million in 2017) and as loss within "Finance income (expense)" for €307 million (income for €837 million in 2017).

(c) Income or expense were recognized in the profit and loss account within "Income (expense) from investments — Dividends".

(d) Income or expense were recognized in the profit and loss account as net impairment losses within "Net (impairment losses) reversal of trade and other receivables" for €415 million (net impairment losses for €913 million in 2017) and as income within "Finance income (expense)" for €69 million (expenses for €45 million in 2017), including interest income calculated on the basis of the effective interest rate of €38 million.

(e) In the profit and loss account, income or expense were recognized as expense within "Finance income (expense)" for €139 million (€116 million in 2017), including interest income calculated on the basis of the effective interest rate of €129 million (€128 million in 2017) and net impairment losses for €275 million.

(f) In the profit and loss account, income or expense were recognized as expense within "Finance income (expense)" for €615 million (€1,137 million in 2017), including interest income calculated on the basis of the effective interest rate of €605 million (€654 million in 2017).

(g) In the profit and loss account, income or expense were recognized within "Net sales from operations" and "Purchase, services and other" as income for €642 million (expense for €54 million in 2017), and as income within "Other operating income (expense)" for €12 million in 2017.

Disclosures about the offsetting of financial instruments

The table below summarizes the disclosures about the offsetting of financial instruments.

(€ million)	Gross amount of financial assets and liabilities	Gross amount of financial assets and liabilities subject to offsetting	Net amount of financial assets and liabilities
December 31, 2018			
Financial assets			
Trade and other receivables	15,634	1,533	14,101
Other current assets	3,894	1,636	2,258
Financial liabilities			
Trade and other liabilities	18,280	1,533	16,747
Other current liabilities	5,616	1,636	3,980
December 31, 2017			
Financial assets			
Trade and other receivables	16,636	1,215	15,421
Other current assets	2,852	1,279	1,573
Financial liabilities			
Trade and other liabilities	17,963	1,215	16,748
Other current liabilities	2,794	1,279	1,515

The offsetting of financial assets and liabilities related to the offsetting of: (i) assets and liabilities for current financial derivatives for €1,636 million (€1,279 million at December 31, 2017); and (ii) receivables and payables pertaining to the Exploration & Production segment towards state entities for €1,347 million (€1,041 million at December 31, 2017); (iii) trade receivables and trade payables pertaining to Eni Trading & Shipping Inc for €186 million (€174 million at December 31, 2017).

Legal Proceedings

Eni is a party in a number of civil actions and administrative arbitral and other judicial proceedings arising in the ordinary course of business. Based on information available to date, and taking into account the existing risk provisions disclosed in note 20 — Provisions for contingencies and that in some instances it is not possible to make a reliable estimate of contingency losses, Eni believes that the foregoing will likely not have a material adverse effect on the Group Consolidated Financial Statements.

A description of the most significant proceedings currently pending is provided in the following paragraph. Unless otherwise indicated, no provisions have been made for these legal proceedings as Eni believes that negative outcomes are not probable or because the amount of the provision cannot be estimated reliably.

1. Environment, health and safety

1.1 Criminal proceedings in the matters of environment, health and safety

(i) Syndial SpA (company incorporating EniChem Agricoltura SpA — Agricoltura SpA in liquidation — EniChem Augusta Industriale Srl — Fosfotec Srl) — Proceeding about the industrial site of Crotone. In 2010 a criminal proceeding started before the Public Prosecutor of Crotone relating to allegations of environmental disaster, poisoning of substances used in the food chain and omitted clean-up due to the activity at a landfill site which was taken over by Eni's subsidiary in 1991 following the divestment of an industrial complex by Montedison (now Edison SpA). The landfill site had been filled with industrial waste from Montedison activities until 1989 and then no additional waste was discharged there. Eni's subsidiary carried out the clean-up of the landfill in 1999 through 2000. The defendants are certain managers at Eni's subsidiaries that have owned and managed the landfill since 1991. Independent consultants performed an assessment during the 2014. Once the consultants completed their work, the acts returned to the Public Prosecutor of Crotone for the next step and possible indictment. The proceeding continues with the examination of the dismissal request submitted by the defense. The Municipality of Crotone will act as plaintiff. The Prosecutor of Crotone notified the conclusion of the preliminary investigations. In March 2019, the public prosecutor requested the acquittal of all defendants. In April 2017, the Public Prosecutor of Crotone had started another criminal proceeding concerning the clean-up of the area called "Farina Trappeto". The Company presented a new clean-up project already deemed approvable by the Ministry of the Environment. Final authorizations for this project are pending. The Company requested to dismiss also this second proceeding.

(ii) Syndial SpA and Versalis SpA — Porto Torres — Prosecuting body: Public Prosecutor of Sassari. In July 2011, the Public Prosecutor of Sassari (Sardinia) resolved that a number of officers and senior managers of companies engaging in petrochemical operations at the site of Porto Torres, including the manager responsible for plant operations of the Company's subsidiary Syndial, would stand trial due to allegations of environmental damage and poisoning of water and crops. The Province of Sassari, the Municipality of Porto Torres and other entities have been acting as plaintiffs. The Judge for the Preliminary Hearing admitted as plaintiffs the above-mentioned parts, but based on the exceptions issued by Syndial on the lack of connection between the action and the charge, denied that the claimants would act as plaintiff with regard to the serious pathologies related to the existence of poisoning agents in the marine fauna of the industrial port of Porto Torres. In February 2013, the Prosecutor of Sassari notified the conclusion of preliminary investigations and requested a new imputation for negligent behaviour instead of illicit conduct. In the conclusions of the preliminary hearing, the Court of Sassari dismissed the accusation because of the statute of limitations. The Public Prosecutor filed an appeal before the Third Instance Court. After a hearing on a question of constitutional legitimacy concerning the period for the statute of limitations for the crime of disaster, the Third Instance Court recognized its validity and therefore accepted the claim and sent all the acts to the Constitutional Court. The Constitutional Court declared the question unfounded, considering that the statute of limitations for fraudulent hypothesis and the corresponding culpable hypothesis is an expression of a non-unreasonable legislative discretion, assuming that, in relation to certain culpable offenses causing social alarm, the complexity of the necessary investigations justifies a lengthening of the limitation periods. The Third Instance Court returned the documents to the Public Prosecutor of Sassari who proceeded to resubmit the request for indictment. The preliminary hearing is underway.

(iii) Syndial SpA and Versalis SpA — Porto Torres dock. In July 2012, the Judge for the Preliminary Hearing, following a request of the Public Prosecutor of Sassari, requested the performance of a probationary evidence relating to the functioning of the hydraulic barrier of Porto Torres site (ran by Syndial SpA) and its capacity to avoid the dispersion of contamination released by the site in the near portion of sea. Syndial SpA and Versalis SpA have been notified that its chief executive officers and other managers are being investigated. The Public Prosecutor of the Municipality of Sassari requested that the above-mentioned individuals would stand trial. The plaintiffs, the Ministry of Environment and the Sardinia Region, claimed environmental damage in an amount of €1.5 billion. On the hearing dated July 2016, the Judge pronounced an acquittal sentence for all defendants of Syndial and Versalis with respect to the crimes of environmental disaster. Three Syndial managers were found guilty of environmental disaster which took place in the area in the period limited to August 2010 — January 2011 and condemned to one-year prison, with a suspended sentence. The Judge did not mention any possible malfunctioning of the hydraulic barrier of Porto Torres site or ineffective implementation of any emergency safety measure, as claimed by the Public Prosecutor. Syndial filed an appeal against this decision.

(iv) Syndial SpA — The illegal landfill in Minciaredda area, Porto Torres site. In July 2015, the Judge for the Preliminary Hearing of the Court of Sassari, on request of the Public Prosecutor, seized of the Minciaredda landfill area, near the western border of the Porto Torres site (Minciaredda area). All the indicted have been served a notice of investigation for alleged crimes of carrying out illegal waste disposal and environmental disaster. The seizure provision involved as well Syndial in accordance with the Legislative Degree No. 231/01. With reference to the clean-up activities in the Minciaredda area, on January 27, 2016 the relevant administrative body approved the project for the soil clean-up in the Minciaredda area. Syndial obtained all the necessary ministerial and judicial authorizations to start the remediation project. Following the preliminary investigations, the Public Prosecutor requested a referral to trial. Some environmental associations joined the proceeding as plaintiffs. The proceeding is still pending.

(v) Syndial SpA — The Phosphate deposit at Porto Torres site (1). In 2015, the Judge for the Preliminary Hearing of the Court of Sassari, accepting a request of the Public Prosecutor of Sassari, seized — as a preventive measure — the area of "Palte Fosfatiche" (phosphates deposit) located on the territory of Porto Torres site, in relation to alleged crimes of environmental disaster, carrying out of unauthorized disposal of hazardous wastes and other environmental crimes. Subsequent to a specific request, both the Public security officer of Sassari and the Judge for the Preliminary Hearing of the Court of Sassari authorized to implement better delimitations of the landfill area, to provide the area with devices for monitoring the level of environmental pollutants and meteoric waters. The investigations are underway.

(vi) Syndial SpA — Phosphate deposit at Porto Torres site (2). In 2015, the Public Prosecutor at the Court of Sassari seized — as a probative measure — the containment systems for the meteoric waters in the area "Palte Fosfatiche" (phosphates deposit). These waters are being collected by Syndial following authorizations of the Public security officer of Sassari and the Judge for the Preliminary Hearing of the Court of Sassari. The indicted have also been served a notice of investigation for alleged crimes of omitted clean-up and management of radioactive waste. The Public Prosecutor decided to suspend the activities of collection, containment and preservation of the area, in spite that those activities have already been authorized. The request filed for the removal of the phosphates deposit was authorized by the Public Prosecutor in October 2018. The investigations are underway.

(vii) Syndial SpA — Proceeding on the asbestos at the Ravenna site. A criminal proceeding is pending before the Tribunal of Ravenna about the crimes of culpable manslaughter, injuries and environmental disaster, which would have been allegedly committed by former Syndial employees at the site of Ravenna. The site was taken over by Syndial following a number of corporate mergers and acquisitions. The alleged crimes date back to 1991. In the proceeding there are 75 alleged victims. The plaintiffs include relatives of the alleged victims, various local administrations, and other institutional bodies, including local trade unions. The advocacy of Syndial claimed the statute of limitation about the instance of environmental disaster for certain instances of diseases and deaths. The Judge for the Preliminary Hearing at Ravenna decided that all defendants would stand trial and ascertained the statute of limitation only with reference to certain instances of crime of culpable injury. Syndial signed some settlements. In November 2016, the Judge acquitted the defendants for all the contested cases except for one for which ruled a decision of conviction. The defendants, the Prosecutor and the plaintiffs appealed the decision. The proceeding was suspended following the filing of an appeal before the Third Instance Court.

(viii) Raffineria di Gela SpA-Eni Mediterranea Idrocarburi SpA — Alleged environmental disaster. A criminal proceeding is pending in relation to crimes allegedly committed by the managers of the Raffineria di Gela SpA and EniMed SpA relating environmental disaster, unauthorized waste disposal and unauthorized spill of industrial wastewater. The Gela Refinery has been sued for administrative offence in accordance with the Legislative Decree No. 231/01. This criminal proceeding initially regarded soil pollution allegedly caused by spills from 14 tanks of the refinery storage, which had not been provided with double bottoms, and pollution of the sea water near the coastal area adjacent to the site due to the failure of the barrier system implemented as part of the clean-up activities conducted at the site. At the closing of the preliminary investigation, the Public Prosecutor of Gela merged into this proceeding the other investigations related to the pollution occurred at the other sites of the Gela refinery as well as hydrocarbon spills at facilities of EniMed. The proceeding is pending at the preliminary hearings.

(ix) Eni SpA — Proceeding Val d'Agri. On March 2016, the Italian Public Prosecutor's Office of Potenza started a criminal investigation in order to ascertain the existence of an illegal handling of waste material produced at the Viggiano oil center (COVA), part of the Eni-operated Val d'Agri oil complex. After a two-year investigation, the Prosecutors decided for the domiciliary detention of 5 Eni employees and to put under seizure certain plants functional to the production activity of the Val d'Agri complex which, consequently, was shut down (60 KBOE/d net to Eni). From the commencement of the investigation, Eni has carried out several technical and environmental surveys, with support of independent experts of international reach, who recognized a full compliance of the plant and the industrial process with requirements of the applicable laws, as well as with best available technologies and international best practices. The Company studied certain corrective measures to upgrade plants which, although being not a structural solution, were intended to address the claims made by the public prosecutor about an alleged operation of blending which would have occurred during normal plant functioning. Those measures comprised building a gathering system of inherent liquid associated with the extraction of hydrocarbons at the gas lines. Those corrective measures were favourably reviewed by the Public Prosecutor. The Company restarted the plant through re-injections into the Costa Molina 2 well on August 2016. Simultaneously, a local administrative agency (the Region) requested a new administrative procedure to grant Eni a comprehensive environmental authorization to operate the facilities. In relation to the criminal proceeding, the Public Prosecutor's Office requested the indictment for all the defendants and the Company. At the preliminary hearing held in April 2017, prosecutor reiterated its request of indictment. The trial started in November 2017 and is in the hearings stage.

(x) Eni SpA — Health investigation related to the COVA center. Beside the criminal proceeding for illegal trafficking of waste, the Public Prosecutor started another investigation in relation to alleged health violations. The Public Prosecutor requested the formal opening of an investigation with respect to nine people in relation to alleged violations of the rules providing for the preparation of a Risk Assessment Document of the working conditions at the Val d'Agri Oil Center (COVA). In March 2017, following the request of the Consultant of the Prosecutor, the Labor Inspectorate of Potenza issued a fine against the employers of the COVA for omitted and incomplete assessment of the chemical risks for the COVA center. In October 2017, following the request of the Consultant of the Prosecutor, the National Mining Office for Hydrocarbons and Geo-resources (UNMIG) requested the transfer to a different task of 25 employees of the COVA center for improper assessment of their suitability to the current tasks expressed by the Eni personnel in charge of assessing the health risk profile of employees. Against this decision, the Company filed a formal objection and the UNMIG repealed the resolution issued. Furthermore, in October 2017, the Prosecutor's Office changed the crime allegations to disaster, murder and negligent personal injury, also alleging breaches of health and safety regulations. Given the level of risk, in December 2017, Eni filed a request for pre-trial hearing for gathering evidence on the matter that was rejected by the Judge.

(xi) Eni SpA — Proceeding Val d'Agri — Tank spill. On February 2017, the Italian police department of Potenza ascertained a stream of water contaminated by hydrocarbon traces of unknown origin, flowing inside a little shaft located outside the Val d'Agri Oil Center (COVA). The activities carried out by Eni at the COVA aimed at reconstructing the origin of the contamination and have identified the cause in a failure of a tank, while outside of the COVA, following the environmental monitoring implemented, emerged a risk — currently averted — of extension of the contamination in the downstream area of the plant. In executing these activities, Eni performed all the communications provided for by the Legislative Decree 152/06 and started certain emergency safe-keeping operations at the areas subject to contamination outside the COVA. Furthermore, the Company completed the arrangement plan for the internal and external areas of the COVA, whose final report was examined by the relevant authorities. Following this event, a criminal investigation was initiated in order to ascertain the existence of illicit environmental pollution against the former COVA officers, the Operation Managers in charge since 2011 and the HSE Manager in charge at the time of the accident, and also against Eni in relation to the same offense pursuant to the Legislative Decree 231/01 as communicated in December 2018 following the notification of the extension of the terms for preliminary investigations and of some public officials belonging to local administrations for official misconduct, false and fraudulent public statements committed in 2014 and of crime for environmental disaster and of culpable conduct committed in February 2017. Investigations are ongoing. In April 2017, Eni, on its own initiative, suspended the industrial activity at the COVA, anticipating the provisions of the Regional Council Resolution. In July 2017, Eni restarted the plant's operational activities. The resumption follows the approval from the Basilicata Region confirming the functionality of the plant and the presence of all necessary safety conditions. During the temporary closure, Eni performed all the requirements provided for by the relevant authorities, including the provision of a double bottom to the tank where the spillage occurred. The Company compensated the damage to certain landlords of areas close to the COVA, which were affected by the spillover. Discussions are ongoing with other claimants. In February 2018, Eni contested the reports presented in October and in December 2017 by the Italian Fire Department stating that it does not consider itself obliged to carry out the integration required, considering that the data acquired in the area affected by the event indicate that the loss was promptly and efficiently controlled and there were no situations of serious danger to human health and the environment.

(xii) Raffineria di Gela SpA-Eni Mediterranea Idrocarburi SpA — Waste management of the landfill Camastra. In June 2018, Eni's subsidiaries Raffineria di Gela SpA and Eni Mediterranea Idrocarburi SpA were notified by the Public Prosecutor of Palermo (Sicily) of a notice of conclusion of preliminary investigations relating allegations of unlawful disposal of industrial waste deriving from the reclaiming activities of soil, which were discharged at a landfill owned by a third party. The Prosecutor charged the alleged crime against the then chief executive officers of the two subsidiaries, whereas the legal entities have been charged with the liability pursuant by Legislative Decree No. 231/01. The alleged wrongdoing related to the willful falsification of the waste certification for purpose of discharging at the landfill.

(xiii) Syndial SpA — Environmental disaster at Ferrandina. In January 2018, the Public Prosecutor of Matera commenced a criminal proceeding against a manager of the Eni subsidiary Syndial based on allegations of unlawful handling of waste and environmental disaster as part of the reclaiming activities performed at an industrial site (Ferrandina/Pisticci in the south of Italy). The charge related to an alleged spillover of effluent in the subsoil and then in a nearby river due to a damaged pipe dedicated to the transportation of effluent to a disposal plant owned by a third party. Following an interrogation of the investigated manager, the prosecutor resolved to request his indictment.

(xiv) Versalis SpA — Preventive seizure at the Priolo Gargallo plant. In February 2019, the Court of Syracuse on request of the public prosecutor ordered the precautionary seizure of the Priolo/Gargallo plant as part of an ongoing investigation about air emissions at the industrial complex. However, the Eni subsidiary has been given permission to continue running the industrial activity at the plant. A preliminary review performed by technical consultants appointed by the public prosecutor, found that the spots of the plant designed to channel and release emissions compliance failed to comply with best available techniques (BAT). The Tribunal measure comprised certain interrelations between BATs and the obtained Environmental Integrated Authorizations, which according to the consultants would not be legitimate because they have been found to be inconsistent with applicable regulations. Few years ago Versalis implemented certain plant upgradings designed to comply with measures requested by the public prosecutor and his consultants. Based on this, management filed an appeal against the measure of precautionary seizure of the plant before a Review Court. On March 26, 2019, the Review Court annulled the decree and ordered the release of seizure of the plant.

(xv) Eni SpA — Fatal accident Ancona offshore platform. On March 5, 2019, a fatal accident occurred at the Barbara F platform in the offshore of Ancona. On the basis of the first investigations, part of the structure on which a crane and the relative control cabin was installed fell into the sea striking a supply vessel and causing injuries to two contract workers and the death of an Eni employee who was inside the control cabin of the crane. The Public Prosecutor of Ancona opened an investigation against unknown persons and ordered further technical appraisals relating the crane.

1.2 Civil and administrative proceedings in the matters of environment, health and safety

(i) Syndial SpA — Summon for alleged environmental damage caused by DDT pollution in the Lake Maggiore — Prosecuting body: Ministry for the Environment. In May 2003, the Ministry for the Environment summoned Syndial requesting the compensation of an alleged environmental damage caused by the activity at the Pieve Vergonte plant in the years 1990 through 1996. With a temporarily executive sentence dated July 2008, the District Court of Turin sentenced the subsidiary Syndial SpA to compensate environmental damages amounting to €1,833.5 million, plus legal interests accrued from the filing of the decision. Eni and its subsidiary deemed the amount of the environmental damage to be absolutely groundless as the sentence lacked sufficient elements to support such a material amount of the liability charged with respect to the volume of pollutants ascertained by the Italian Environmental Minister. In July 2009, Syndial filed an appeal against the above-mentioned sentence, and consequently the proceeding continued before a Second Degree Court of Turin that requested a technical appraisal on the matter. The consultants validated the technical appraisal and the other technical assessments that were carried out by the Company together with local and national technical entities. The consultants concluded that: (i) no further measure for environmental restoration is required; (ii) there was no significant and measurable impact on the environment of the ecosystem, therefore no restoration or damage compensation should be claimed. The only impact which could be recorded concerned the fishing activity, with an estimated damage of €7 million which could be already restored through the measures proposed by Syndial; (iii) the necessity and convenience of dredging should be definitely excluded, both from the legal and scientific point of view, while confirming technical and scientific correctness of the Syndial's approach based on the monitoring of the process of natural recovery, which is estimated to require 20 years. In March 2017, the Second Degree Court: (i) excluded the application of compensation for monetary equivalent (Article 18 of Law 349/1986); (ii) annulled the monetary compensation of €1.8 billion requesting Syndial to perform the already approved cleanup project of the polluted areas, which comprise groundwater, as well as compensatory remediation works. The value of these compensatory works required by the Court, in case of Syndial failure or misperformance, is estimated at €9.5 million. The cleanup project filed by Syndial was ratified by local and governmental authorities and is currently being executed. Expenditures expected to be incurred have been provisioned in the environmental provision. Any other claims filed by the Italian Minister for the Environment were rejected (including compensation for non-material damage). In April 2018, the Ministry for the Environment filed an appeal to the Third Instance Court. In accordance with the law, the Company and its managers filed an appeal and a counter-appeal.

(ii) Syndial SpA — Versalis SpA — Eni SpA (R&M) — Augusta harbor. The Italian Ministry for the Environment with various administrative acts required companies that were running plants in the petrochemical site of Priolo to perform safety and environmental remediation works in the Augusta harbor. Companies involved include Eni subsidiaries Versalis, Syndial and Eni Refining & Marketing Division. Pollution has been detected in this area primarily due to a high mercury concentration that is allegedly attributed to the industrial activity of the Priolo petrochemical site. The above-mentioned companies contested these administrative actions, objecting in particular the nature of the remediation works decided and the methods whereby information on the pollutants concentration has been gathered. A number of administrative proceedings started on this matter were subsequently merged before the Regional Administrative Court of Catania. In October 2012, the Court ruled in favor of Eni's subsidiaries against the Ministry prescriptions about the removal of the pollutants and the construction of a physical barrier. In September 2017, the Ministry notified all the companies involved of a formal notice for the start of remediation and environmental restoration of the Augusta harbor within 90 days. The act, contested by the co-owner companies in December 2017, constitutes a formal notice for environmental damage. The Administrative Council of the Sicilian Region ruled on the appeals pending against various sentences of the Regional Administrative Court and essentially confirmed the cancellation of all administrative provisions subject to the dispute. The prescriptive framework for the companies thus becomes clear and definitive. The annulment of the provisions has, inter alia, retroactive effect at the time of their adoption and therefore allows to exclude the risk of claims against any possible breach of administrative provisions.

(iii) Eni SpA — Syndial SpA — Raffineria di Gela SpA — Claim for preventive technical inquiry. In February 2012, Eni's subsidiaries Raffineria di Gela SpA and Syndial SpA and the parent company Eni SpA (involved in this matter through the operations of the Refining & Marketing Division) were notified of a claim issued by the parents of children born malformed in the Municipality of Gela between 1992 and 2007. The claim for preventive technical inquiry aimed at verifying the relation of causality between the malformation pathologies suffered by the children of the plaintiffs and the environmental pollution caused by the Gela site (pollution deriving from activities conducted at the industrial plant by Raffineria di Gela SpA and Syndial SpA), quantifying the alleged damages suffered and eventually identifying the terms and conditions to settle the claim. In any case, the same issue was the subject of previous criminal proceedings, of which one closed without ascertainment of any illicit behavior on the part of Eni or its subsidiaries, while a further criminal proceeding is still pending. The consultants appointed by the Court and those designated by the plaintiffs performed a technical appraisal on the matter, reaching very different outcomes. Thus, parties failed to reach a settlement of the matter. On December 2015, the three companies involved were sued in relation to a total of 30 cases of compensation for damages in civil proceedings. The proceedings are still pending. n May 2018, the Court issued a first instance judgment concerning one case. The Judge rejected the claim for damages, acknowledging the goodness and reasonableness of the arguments of the defendant companies in relation to the absence of evidences concerning the existence of a causal link between the pathologies and the alleged industrial pollution. The first-degree sentence was appealed before the Court of Caltanissetta.

(iv) Syndial SpA — Environmental claim relating to the Municipality of Cengio. The Ministry for the Environment and the Delegated Commissioner for Environmental Emergency in the territory of the Municipality of Cengio summoned Syndial before a Civil Court and sentenced Eni's subsidiary to compensate the environmental damage relating to the site of Cengio. The request for environmental damage amounted to €250 million to which add health damage to be quantified during the proceeding. The plaintiffs accused Syndial of negligence in performing the clean-up and remediation of the site. In February 2013, the Court ruled a technical appraisal to verify the existence of the environmental damage. Following failed attempts to define a settlement agreement on the matter among the parties involved, the Judge resumed the trial and requested an independent appraisal on the matter. A first stage of the trial was filed in September 2018. The proceeding is still at the preliminary stage.

(v) Syndial SpA and Versalis SpA — Summon for alleged environmental damage caused by illegal waste disposal in the municipality of Melilli (Sicily). In May 2014, the Municipality of Melilli summoned Eni's subsidiaries Syndial and Versalis for the environmental damage allegedly caused by carrying out illegal waste disposal activities and unauthorized landfill. In particular, the plaintiff claimed the responsibilities of Syndial and Versalis for the production of waste and because they commissioned the waste disposal. The plaintiff stated that this illegal handling of waste was part of certain criminal proceedings dating back to 2001 – 2003 which would have allegedly traced the hazardous waste materials back to the Priolo and Gela industrial sites that are managed by the above-mentioned Eni's subsidiaries (in particular, the waste with high mercury concentration and railway sleepers no longer in use). Such waste was allegedly handled and disposed illegally at an unauthorized landfill owned by a third party (located about 2 kilometers away from the town of Melilli). Two subsidiaries of Eni and a third-party waste company were claimed to be jointly and severally liable of damage amounting to €500 million. The third-party company executed waste disposal at the site. In June 2017, the Judge accepted all the defensive instances of Syndial and Versalis, judging the requests of the Municipality to be inadmissible for lack of locus standi and considering the requests as unfounded or unproved, and sentenced the Municipality to the reimbursement of the expenses of the proceeding. In September 2017, the Municipality appealed the ruling requesting a new investigation and the admission of a technical appraisal, as well as the suspension of the enforcement of the sentence of first instance. The court of appeal rejected the counterclaim filed by the Municipality, which then filed an appeal before a third-degree court to obtain the repeal of the part of the sentence about the expenses of the judgement, where Eni's subsidiaries are part. Furthermore, the Municipality filed an appeal to overturn the first-degree sentence before another court in Sicily, where the Eni's subsidiaries are planning to take part.

2. Court inquiries

(i) Eni SpA — Reorganization procedure of Alitalia Linee Aeree Italiane SpA under extraordinary administration. On January 2013, the Italian airline company Alitalia, which was undergoing a reorganization procedure, summoned Eni, Exxon Italia and Kuwait Petroleum Italia SpA before the Court of Rome, to obtain a compensation for alleged damages caused by a presumed anti-competitive behavior on part of the three petroleum companies in the supply of jet fuel in the years 1998 through 2009. The claim was based on a deliberation filed by the Italian Antitrust Authority in June 2006. The antitrust deliberation accused Eni and other five petroleum companies of anti-competitive agreements designed to split the market for jet fuel supplies and blocking the entrance of new players in the years 1998 through 2006. The antitrust findings were substantially endorsed by an administrative court. Alitalia has made a claim against the three petroleum companies jointly and severally presenting two alternative ways to assess the alleged damages. A first assessment of the overall damages amounted to €908 million. This was based on the presumption that the anti-competitive agreements among the defendants would have prevented Alitalia from autonomously purchasing supplies of jet fuel in the years when the existence of the anti-competitive agreements were ascertained by the Italian Antitrust Authority and in subsequent years until Alitalia ceased to operate airline activity. Alitalia asserted the incurrence of higher supply costs of jet fuel of €777 million excluding interest accrued and other items that add to lower profitability caused by a reduced competitive position in the marketplace estimated at €131 million. Another assessment of the overall damage made by Alitalia stand at €395 million of which €334 million of higher purchase costs for jet fuel and €61 million of lower profitability due to the reduced competitive position on the marketplace. With a decision dated May 2014, the Court of Rome declared the connection with a judgment previously proposed by Alitalia itself before the Court of Milan against other oil companies participating to an alleged cartel agreement. The case was thus summed up by Alitalia before the Court of Milan. In September 2017, the Court of Milan ruled that: (i) the requests of Alitalia for the period 1998 – 2004 were prescribed; (ii) for the period subsequent to June 2006, no further assessment should be carried out, since Alitalia has failed to meet its burden of allegation; (iii) for the period between December 2004 and June 2006, a specific technical appraisal will be carried out. The judgment is pending in the first instance at the preliminary stage awaiting the fulfillment of the technical appraisal. Eni accrued a provision with respect to this proceeding.

(ii) Eni's arbitration with GasTerra. In 2013, Eni initiated an arbitration against GasTerra, as part of a long-term supply contract signed in 1986, to obtain a revision of the price charged by GasTerra to Eni for the gas supplied in the 2012 – 2015 period. On that occasion, Eni and GasTerra agreed to apply a provisional price, which was lower than the previous price, until the definition of a new contractual price based on an arrangement between parties or an arbitration award. The arbitration award dismissed Eni's claim for price revision, without however determining a new price applicable in the relevant period. GasTerra considered that, by dismissing Eni's claim, the award restored the original contract price, based on which GasTerra now claims an additional amount to be paid by Eni which corresponds to the difference between the provisional price and the contractual price. Eni, relying also on the opinion of its external consultants, does not agree with GasTerra's interpretation and considers GasTerra's claim groundless. However, GasTerra, based on its own interpretation, commenced an arbitration and obtained from a Dutch court the provisional seizure of Eni's investment in its subsidiary Eni International BV (which at the time of the seizure i.e. at the reporting date June 30, 2016, stated consolidated net assets of €34.7 billion) for the alleged receivable due by Eni (equal to €1.01 billion). With respect to the interim seizure measure obtained by GasTerra, Eni offered to GasTerra, who in turn accepted, a bank guarantee of the same amount of the GasTerra claim. This guarantee is expected to remain effective until a final award by the arbitration procedure. The measure, which was granted after a summary review only and without Eni being heard, does not prejudice the outcome on the merits of the claims. The correct interpretation of the arbitration award and the 2012-2015 price revision will be subject to a new arbitration procedure.

3. Proceedings concerning criminal/administrative corporate responsibility

(i) EniPower SpA. In June 2004, the Public Prosecutor of Milan commenced inquiries into contracts awarded by Eni's subsidiary EniPower and on supplies from other companies to EniPower. It emerged that illicit payments were made by EniPower suppliers to a manager of EniPower who was immediately fired. The Court served EniPower (the commissioning entity) and Snamprogetti (now Saipem SpA) (contractor of engineering and procurement services) with notices of investigation in accordance with Legislative Decree No. 231/01 that establishes that the companies are liable for the crimes committed by their employees who acted on behalf of the employer. In August 2007, Eni was notified that the Public Prosecutor requested the dismissal of EniPower SpA and Snamprogetti SpA, while the proceeding continues against former employees of these companies and employees and managers of the suppliers under the provisions of Legislative Decree No. 231/01. Eni SpA, EniPower and Snamprogetti presented themselves as plaintiffs. In September 2011, the Court of Milan found that nine persons were guilty for the above-mentioned crimes. In addition, they were sentenced jointly and severally to the payment of all damages to be assessed through a specific proceeding and to the reimbursement of the proceeding expenses incurred by the plaintiffs. The Court also resolved to dismiss all the criminal indictments for 7 employees, representing some companies involved as a result of the statute of limitations, while the trial ended with an acquittal of 15 individuals. In relation to the companies involved in the proceeding, the Court found that 7 companies are liable based on the provisions of Legislative Decree No. 231/01, imposing a fine and the disgorgement of profit. Eni SpA and its subsidiaries, EniPower and Saipem, which took over Snamprogetti, acted as plaintiffs in the proceeding also against the mentioned companies. The Court rejected the position as plaintiffs of the Eni Group companies, reversing the prior decision made by the Court. This decision may have been made based on a pronouncement made by a Supreme Court that stated the illegitimacy of the constitution as plaintiffs against any legal entity, as indicted under the provisions of Legislative Decree No. 231/01. The condemned parties filed appeal against the above-mentioned decision. The Appeal Court issued a ruling that substantially confirmed the first-degree judgment except for the fact that it ascertained the statute of limitation with regard to certain defendants. In 2015, the Supreme Court annulled the judgment of the Second Degree Court ascribing the judgment to another section that, once more, confirmed the sentence of first instance, excepting the rulings of the previous appeal sentence not subject to annulment, including the statute of limitation. The grounds of the sentence have been filed confirming the motivations provided by the previous instance courts. An appeal was filed at the Third Instance Court solely for the purposes of the civil proceeding.

(ii) Algeria. Legal proceedings are pending in Italy and outside Italy in connection with an allegation of corruption relating to the award of certain contracts to Eni's former subsidiary Saipem in Algeria. In February 2011, Eni received from the Public Prosecutor of Milan an information request pursuant to the Italian Code of Criminal Procedure. The request related to allegations of international corruption and pertained to certain activities performed by Saipem Group companies in Algeria (in particular the contract between Saipem and Sonatrach relating to the construction of the GK3 gas pipeline and the contract between Galsi, Saipem and Technip relating to the engineering of the ground section of a gas pipeline). The crime of international corruption is among the offenses contemplated by the Italian Legislative Decree No.231/01 which provides for corporate liability for crimes committed by employees and prescribes punishments including fines and the disgorgement of profit. Eni also voluntarily provided to the Public Prosecutor documentation relating to the MLE project (in which Eni's Exploration & Production Division participates), with respect to which investigations in Algeria are ongoing. In November 2012, the Public Prosecutor served Saipem a notice stating that it had commenced an investigation for alleged liability of the company for international corruption in accordance with Legislative Decree No. 231/01. Furthermore, the Public Prosecutor requested the production of certain documents relating to certain activities in Algeria. Subsequently, the Public Prosecutor's Office notified further measures and requests to Saipem, aimed at acquiring further documentation, in particular relating to certain intermediary contracts and sub-contracts entered into by Saipem in connection with its Algerian business. Several former Saipem employees were also involved in the proceeding, including the former CEO of Saipem, who resigned from the office in December of 2012, and the former Chief Operating Officer of the Business Unit Engineering & Construction of Saipem, the employment of whom was terminated at the beginning of 2013. In February 2013, on mandate from the Public Prosecutor of Milan, the Italian Finance Police visited Eni's headquarters in Rome and San Donato Milanese and executed searches and seized documents relating to Saipem's activity in Algeria. On the same occasion, Eni was served a notice that an investigation had commenced in accordance with Legislative Decree No. 231/01 with respect to Eni, Eni's former CEO, Eni's former CFO and another senior manager. Eni's former CFO had previously served as Saipem's CFO, including during the period in which alleged corruption took place and before being appointed as CFO of Eni on August 1, 2008. Following receipt of this notice, Eni conducted an internal investigation with the assistance of external consultants, in addition to the review activities performed by its audit and internal control departments and a team dedicated to the Algerian matters. During 2013, the external consultants reached the following results: (i) the review of the documents seized by the Milan prosecutors and the examination of internal records held by Eni's global procurement department did not find any evidence that Eni entered into intermediary or any other contractual arrangements with the third parties involved in the prosecutors' investigation; the brokerage contracts that were identified, were signed by Saipem or its subsidiaries or predecessor companies; and (ii) the internal review made on the MLE project, the only project that Eni understands to be under the prosecutors' investigation where the client is an Eni Group company did not find evidence that any Eni employee engaged in wrongdoing in connection with the award to Saipem of two main contracts to execute the project (EPC and Drilling). Furthermore, in 2014, with the assistance of external consultants, Eni completed a review of the extent of its operating control over Saipem with regard to both legal, accounting and administrative issues. The findings of that review confirmed the autonomy of Saipem from the parent company during the relevant periods. The findings of

Eni's internal review have been provided to the Judicial Authority in order to reaffirm Eni's willingness to fully cooperate. In January 2015, the Public Prosecutor notified the conclusion of preliminary investigations relating to Eni, Saipem and eight persons (including, the former CEO and CFO of Eni and the Chief Upstream Officer of Eni who was responsible for Eni Exploration & Production activities in North Africa at the time of the events under investigation). The Public Prosecutor issued a notice of alleged international corruption against all such persons (including Eni and Saipem on the basis of the provisions of Legislative Decree No. 231/01) in connection with the entry into intermediary contracts by Saipem in Algeria. Furthermore, some of the defendants (including the former CEO and CFO of Eni and the Chief Upstream Officer of Eni) were accused of tax offenses for alleged fraudulent misrepresentation in relation to the accounting treatment of these contracts for the fiscal years 2009 and 2010. After receiving (i) the evidence collected in connection with the Public Prosecutor's request to take testimony of two individuals under investigation in late 2014, and (ii) the minutes of the preliminary hearing and the documents filed in connection with the conclusion of the preliminary investigation, Eni requested that its consultants perform additional analysis and investigation. As a result, Eni's consultants reaffirmed their conclusions previously reported to the Company. In February 2015, the Public Prosecutor requested the indictment of all the investigated persons for international corruption as well as the tax offenses mentioned above. In 2015, the Judge for the Preliminary Hearing of the Court of Milan dismissed the case and granted an acquittal in favor of Eni, former Chief Executive Officer and Chief Upstream Officer for all the alleged offenses. In February 2016, the Court of Third Instance, upholding an appeal presented by the Public Prosecutor, reversed the dismissal, annulled the verdict, and remanded the proceedings to another Judge for the Preliminary Hearing in the Court of Milan. As a result of the new preliminary hearing in July 2016, the Judge ordered the trial for all defendants, including Eni. Trial began in February 2017. At a hearing in February 26, 2018, the Public Prosecutor, concluding his indictment, requested – among other things – the imposition on Eni of a pecuniary sanction. In September 2018, the Court of Milan rejected in part the charges of the Public Prosecutor and issued an acquittal verdict for Eni, for the former CEO and for the Company's Chief Upstream Officer in relation to all charges. The former CFO of Eni was also acquitted of charges relating to Eni's involvement in the MLE Project. The other defendants in the case, including Saipem, were also convicted of international corruption. In December 2018 the court filed a written opinion setting forth the basis for its rulings. The Public Prosecutor and the parties who were convicted in the first trial have appealed under the terms of the law. A hearing on those appeals is pending.

At the end of 2012, Eni contacted the U.S. Department of Justice (DoJ) and the U.S. SEC in order to voluntarily inform them about this matter, and has kept them informed about the developments in the Italian prosecutors' investigations. Following Eni's notification in 2012, both the U.S. SEC and the DoJ started their own investigations regarding this matter. Eni has furnished various information and documents, including the findings of its internal reviews, in response to formal and informal requests.

(iii) Block OPL 245 — Nigeria. In July 2014, the Public Prosecutor of Milan served Eni with a notice of investigation relating to potential liability on the part of Eni arising from alleged international corruption, pursuant to Italian Legislative Decree No. 231/2001 whereby companies are liable for the crimes committed by their employees when performing their tasks. As part of the investigation, Eni was also subpoenaed for documents and other evidence. According to the subpoena, the proceeding was commenced following a claim filed by NGO ReCommon relating to alleged corruptive practices that according to the Public Prosecutor allegedly involved the Resolution Agreement made on April 29, 2011 relating to the Oil Prospecting License of the offshore oilfield that was discovered in Block 245 in Nigeria ("OPL 245"). Eni fully cooperated with the Public Prosecutor and promptly filed the requested documentation. Furthermore, Eni voluntarily reported the matter to the U.S. Department of Justice and the U.S. SEC. In July 2014, Eni's Board of Statutory Auditors jointly with the Eni Watch Structure resolved to engage an independent, US-based law firm, expert in anticorruption, to conduct a forensic, independent review of the matter, upon informing the Judicial Authorities. After reviewing the matter, the US lawyers concluded in summary that they detected no evidence of wrongdoing by Eni side in relation to the 2011 transaction with the Nigerian government for the acquisition of the OPL 245 license. The outcome of this review was transmitted to the Judicial Authorities. In September 2014, the Public Prosecutor notified Eni of a restraining order issued by a British judge who ordered the seizure of a bank account not pertaining to Eni domiciled at a British bank following a request from the Public Prosecutor. During a hearing before a court in London in September 2014, Eni and its current executive officers stated their non-involvement in the matter regarding the seized bank account. Following the hearing, the Court reaffirmed the seizure. In December 2016, the Public Prosecutor of Milan notified Eni of the conclusion of the preliminary investigation and requested the indictment of Eni's CEO, the Chief Development, Operations and Technological Officer and the Executive Vice President for international negotiations, as well as Eni's former CEO and Eni based on Italian law 231/2001 on corporate entity responsibility. Upon the notification to Eni of the conclusion of the preliminary investigation by the Public Prosecutor, the independent US-based law firm was requested to assess whether the new documentation made available from Italian prosecutors could modify the conclusions of the prior review. The U.S. law firm was also provided with the documentation filed in the Nigerian proceeding mentioned below. The independent U.S. law firm concluded that the reappraisal of the matter in light of the new documentations available did not alter the outcome of the prior review. In December 2017, the Judge for preliminary investigation ordered the indictment of all the parties mentioned above, and other parties under investigation by the Public Prosecutor, before the Court of Milan. During the first trial hearing in March 2018, the the Federal Republic of Nigeria requested permission to join the case as a civil party. Several NGOs, which had made the same request before the Judge of the Preliminary Hearing and been denied, also asked to join as civil parties. At a hearing in May 2018, a Non-Governmental Organization, Asso Consum, also requested to be recognized as a civil claimant in the proceeding. At the subsequent hearing in June 2018, counsel for the Federal Government of Nigeria ("FGN") reiterated the request for the admission as civil claimants in the proceedings of all the parties that sought leave to join the action as civil claimants in March 2018. At the same time, the attorney requested that Eni and Shell be recognized as defendants with respect to those parties' civil claims. Furthermore, a shareholder of Eni asked to be recognized as a civil claimant. At the hearing of July 20, 2018, the Judge (i) granted the FGN's request to join the proceeding as a civil claimant and (ii) rejected that request with respect to the NGOs, Asso Consum and the shareholder of Eni. Therefore, the FGN is the only civil party admitted by the Court. The first instance trial of the Milan Prosecutor's OPL 245 charges began before the Court of Milan on June 20, 2018 and is currently ongoing.

In a separate criminal proceeding, two defendants, neither of whom is a current or former employee of the Company, chose to have their liability determined by the Judge for the Preliminary Hearing on the basis of the evidence presented by the Milan Prosecutor at the preliminary hearing. In September 2018, the Judge convicted these defendants and sentenced them both to four-year detention terms and the disgorgement of profits amounting to approximately €100 million. In December 2018, the Judge for the Preliminary Hearing filed a written opinion setting forth the basis for these rulings. The defendants filed an appeal against this sentence.

In January 2017, Eni's subsidiary Nigerian Agip Exploration Ltd ("NAE") became aware of an Interim Order of Attachment ("Order") issued by the Nigerian Federal High Court upon request from the Nigerian Economic and Financial Crimes Commission (EFCC), attaching OPL 245 temporarily pending a proceeding in Nigeria relating to alleged corruption and money laundering. After making this application, Eni became aware of a formal filing of charges by the EFCC against NAE and other parties. In March 2017, the Nigerian Court revoked the Order. To NAE's knowledge EFCC charges have not been dropped but none of the defendants were served nor arraigned. Eni has provided a copy of the Order and the attached documents, including the charges filed by the EFCC, to the US-based law firm engaged to review the OPL 245 transaction, who upon review of such documents, did not modify their conclusion that they did not detect evidence of wrongdoing by Eni in relation to the acquisition of the OPL 245 from the Nigerian government. In November 2018, Eni SpA and its subsidiaries NAE, NAOC and AENR (as well as some companies of the Shell Group) were notified of the intention of the FGN to bring a civil claim before an English court to obtain compensation for damages allegedly deriving from the transaction that resulted in assignment of the OPL 245 to NAE and Shell subsidiary SNEPCO (Shell subsidiary). Subsequently, Eni obtained a copy of the documentation reflecting the commencement of the case, but neither Eni nor other companies of the Group received any notification regarding this proceeding.

(iv) Congo. In March 2017, the Italian Finance Police served on Eni an information request pursuant to the Italian Code of Criminal Procedure in connection with an investigative file opened by the Public Prosecutor of Milan against unknown persons. The request related in particular to the agreements signed by Eni Congo SA with the Ministry of Hydrocarbons of the Republic of Congo in 2013, 2014 and 2015 in relation to exploration, development and production activities concerning certain permits held by Eni Congo SA for Congolese projects and Eni's relationships with Congolese companies that hold stakes in those projects. In July 2017, the Italian Financial Police, on behalf of the Public Prosecutor of Milan, served Eni with another information request and a notice of investigation pursuant to Italian Legislative Decree No. 231/01 for alleged international corruption. The request expressly stated that it was based in part on the March 2017 information request and concerned the relationship of Eni and its subsidiaries with certain third-party companies from 2012 to the present. Eni produced all of the documentation requested in March and July 2017 and voluntarily disclosed this matter to the relevant US authorities (SEC and DoJ).

On January 26, 2018, the Public Prosecutor's Office requested a six-months extension of the deadline for conducting its preliminary investigation into this matter, from January 31, 2018 until July 30, 2018. Subsequently in July 2018, the Public Prosecutor requested a second extension until February 28, 2019. In April 2018, the Public Prosecutor of Milan served on Eni SpA a further request for documentation and notified an Eni employee, who was the then Chief Development, Operation & Technology Officer, of a search order stating that he and another Eni's employee had been placed resulted under investigation. In October 2018, Public Prosecutor ordered the seizure of an e-mail account of another Eni manager, who was formerly the general director of Eni in Congo during the period 2010 – 2013.

In December 2018, the Public Prosecutor of Milan issued a request to the Company for documents pursuant to article 248 of the Code of Criminal Procedure, concerning some economic transactions between Eni Group companies and certain companies. In February 2019, Eni received an informative note that the preliminary investigations would extend until October 2019.

In April 2018, the Board of Statutory Auditors, the Watch Structure and the Control and Risk Committee of Eni jointly appointed an independent law firm and a professional consulting company, knowledgeable in the matter of anti-corruption, to carry out a forensic review of facts relating to Eni's work in Congo. Based on the preliminary results of such review, that is still on-going, there were no factual evidences about the involvement of Eni, nor of any Eni's employees and key managers in the alleged crimes. On June 4, 2018, the Italian market regulator, Consob, requested information about the above mentioned proceeding from Eni and its Board of Statutory Auditors. Specifically, Eni was asked to provide information about the Congo investigations and the action implemented by the Company and any eventual outcome, including specific audit activities performed by the Company's staff and any task assigned to external parties to review the ongoing investigations. The Company was also asked to transmit supporting evidence and documentation. The Eni Board of Statutory Auditors was asked to report about the monitoring activity performed on the investigations. The Company and its Board of Statutory Auditors answered these requests for information on June 11 and 13, 2018, respectively.

4. Other proceedings concerning criminal matters

(i) Eni SpA (R&M) — Criminal proceedings on fuel excise tax. A criminal proceeding is currently pending, relating to alleged evasion of excise taxes in the context of the retail sales in the fuel market. In particular, the claim states that the quantity of oil products marketed by Eni was larger than the quantity subjected to the excise tax. This proceeding (no. 7320/2014 RGNR) concerns the reunification before the court of three distinct investigations: (i) a first proceeding, opened by the Public Prosecutor's Office of Frosinone involved a company (Turrizziani Petroli) purchaser of Eni's fuel. This investigation was subsequently extended to Eni. The Company fully cooperated and provided all data and information concerning the excise tax obligations for the quantities of fuel coming from the storage sites of Gaeta, Naples and Livorno. Eni collaborated fully, providing all the required documentation. Such proceeding referred to quantities of oil products sold by Eni, allegedly larger than the quantity subjected to the excise tax. After the end of the investigation, the financial police of Frosinone, along with the local Customs Agency, in November 2013 issued a claim related to the missing payment of excise taxes in the 2007 – 2012 period for €1.55 million. In May 2014, the Customs Agency of Rome issued a payment notice relating to the abovementioned claim that was filed by the financial police and Customs Agency of Frosinone. The Company appealed to the Tributary Commission. In March 2018, the Commission filed the ruling of the sentence which accepted Eni's appeal against the claim of the Custom Agency and required the latter to refund the proceeding expenses; (ii) a second proceeding concerning a line of investigation of the Public Prosecutor's Office of Prato, commenced in regard to the deposit of Calenzano and relates to subtraction of fuel through manipulation of the fuel dispensers, subsequently extended also to the Refinery of Stagno (Livorno); (iii) a third proceeding, opened by the Public Prosecutor's Office of Rome, regarded alleged missing payment of excise tax on the surplus of the unloading products, as the quantity of such products was larger than the quantity reported in the supporting fiscal documents. This proceeding represents a development of the first proceeding mentioned above, and substantially concerns similar facts presenting, however, some differences with regard to the nature of the alleged crimes and the responsibility subjected to verification. The second and the third proceeding were merged in the proceeding commenced by Public Prosecutor's Office of Rome. In fact, the Public Prosecutor's Office of Rome has alleged the existence of a criminal conspiracy aimed at habitual subtraction of oil products at all of the 22 storage sites which are operated by Eni over the national territory. Eni is cooperating with the Prosecutor in order to defend the correctness of its operation. On September 2014, a search was conducted at the office of the former chief of the R&M Division in Rome. The motivations of the search are the same as the above-mentioned proceeding as the ongoing investigations also relates to a period of time when the officer was in charge at Eni's R&M Division. On March 2015, the Prosecutor of Rome ordered a search at all the storage sites of Eni's network in Italy as part of the same proceeding. The search was intended to verify the existence of fraudulent practices aimed at tampering with measuring systems functional to the tax compliance of excise duties in relation to fuel handling at the storage sites. In September 2015, the Public Prosecutor of Rome requested a one-off technical appraisal aimed to verify the compliance of the software installed at certain metric heads previously seized with those lodged by the manufacturer at the Ministry of Economic Development. The technical appraisal verified the compliance of the software tested. The proceeding was then extended to a large number of employees and former employees of the company. In November 2017, the Court of Rome, following the request of the Public Prosecutor, ordered a preventive seizure of the oil products meters at Eni's refineries and depots in Italy. The Company, considering the consequences connected to a complete shutdown of the refining and fueling activities, requested the Public Prosecutor to minimize, as much as possible, the impact on customers, companies and service stations. The preventive seizure was revoked, due to the commitments undertaken by the Company which is a third party not subject to investigation. Eni continues to provide full cooperation to the authorities. In December 2017, technical consultants were designated by Eni to verify the integrity of the sites. The results will be provided to the judicial authorities. In March 2018, the Public Prosecutor of Rome notified the conclusion of the preliminary investigations in relation to the criminal proceeding no. 7320/2014 concerning the Calenzano, Livorno, Sannazzaro, Pomezia, Naples, Gaeta and Ortona sites. Based on the outcome of the investigations, as far as Eni is concerned, the proceeding involves former managers and directors of the refineries indicated above concerning alleged aggravated and continuous non-payment of excise duties, alteration and removal of seals, use and possession of false measures and weights. In addition for Calenzano, three employees and their manager of the storage site were indicted on charges alleged procedural fraud. The attorneys of the defendants delivered documentations and requested the public prosecutor to dismiss the case.

In September 2018, Eni received, as offended party, the notification of the schedule of hearing issued by the Court of Rome, in relation to criminal association and other minor claims, against numerous persons under investigation — including over forty Eni employees — subject of a separated proceeding (No. 22066/17 RGNR), for which, in May 2017, the Public Prosecutor's Office had requested the filing. At the end of the hearing in December 2018, the Judge accepted the request for dismissal for several persons under investigation, including thirteen Eni's employees, while he rejected the request, requiring the Public Prosecutor to pronounce the charge in terms and forms of law for twenty-eight Eni employees (including the former managers of the R&M Division) for criminal association. In October 2018, as regards the main criminal proceeding, the Public Prosecutor notified the date for the preliminary hearing and the related request for indictment.

In April 2018 as part of the administrative proceeding intended to collect taxes allegedly not paid by Eni, the tax police of Rome based on the findings of the investigations performed by the prosecutors of Frosinone, Prato and Rome issued a statement of objection against the Company claiming the missed payment of excise taxes due for the years 2008 up to 2017 for €34 million, as well as the related higher corporate profits before income taxes leading to the claim of additional taxes for €22 million related to income taxes and VAT. The Custom Agency that is in charge of issuing the notice of payment may also impose a fine and the recognition of interest expense. A part of the litigation, for which omitted payment is disputed, relates to the same transactions successfully challenged by the Company against the Tax Commission of Rome. The Company will appeal at the appropriate forum. Eni accrued a provision with respect to this proceeding.

(ii) Eni SpA — Public Prosecutor of Milan — Criminal proceeding no. 12333/2017. In February 2018, Eni was notified of a search and seizure decree in relation to allegations of associative crime aimed at slander and at reporting false information to a Public Prosecutor. In the decree, the Prosecutor of Milan included, among the other persons under investigation, the former Chief Legal and Regulatory Affairs Officer of Eni, currently the Chief Gas & LNG Marketing and Power Officer of the Company. Eni is not under investigation. According to the decree, the association would be allegedly aimed at interfering with the judicial activity in certain criminal proceedings that are involving, among others, Eni and some of its directors and managers. Afterwards, the Control and Risks Committee, having consulted the Board of Statutory Auditors, and together with the Watch Structure, agreed to engage an auditing firm to perform an internal audit of all relevant facts and circumstances and all records and documentation on the matter with respect to the events of the aforementioned proceeding, including a forensic review. The final report, submitted to the Control and Risk Committee, the Watch Structure and the Board of Statutory Auditors on September 12, 2018, concluded that following the review carried out with respect to the allegations made by the Public Prosecutor of Milan, there would be no sufficient factual evidence about the involvement of the former Chief Legal manager and Regulatory Affairs manager of Eni in the alleged crimes.

In April 2018, the Board of Directors appointed two external consultants, a criminal lawyer and a civil lawyer to provide independent legal advice in relation to the facts under investigation. The outcomes illustrated in two reports, dated November 22, 2018 and February 14, 2019, did not highlight circumstances in fact suitable any involvement of any Eni's employees in the crimes alleged by the Public Prosecutor. Both reports were presented to the Board of Directors, to the Board of Statutory Auditors and to the Watch Structure of Eni.

On June 4, 2018, Consob, the Italian market regulator, requested to be informed about the above mentioned proceeding. The request was addressed to the Company and to its Board of Statutory Auditors. Specifically, Consob asked for the outcome of the forensic review and to be updated about any other audit action taken in relation to the matter by the Company and by its board of Statutory Auditors. The Board of Statutory Auditors was also requested to report about the findings of the additional audit program agreed with the external auditor regarding the matter and to keep Consob updated about any further initiative adopted. The Company and its Board of Statutory Auditors answered the request of information on June 11 and June 13, 2018, respectively. Subsequently, the Company finalized its response by sending further documentation including the final report of the audit firm and the reports of the consultants of the Board of Directors. The Board of Statutory Auditors has periodically updated Consob of the initiatives taken as part of the Board's monitoring responsibilities with communications transmitted on September 21, December 3 and 20, 2018 and on February 19, 2019.

On June 13 2018, Eni was notified of a request from the Prosecutor Office to transmitting certain documentation in accordance with the Italian penal code. The request targeted evidence and documents relating to the internal audit performed by the Company and any possible external review concerning certain tasks that were assigned to an external lawyer with respect to Eni. This lawyer appears to be investigated as part of this proceeding. The reports of the consultants of the Board of Directors and of the independent third party were sent to the Judicial Authority.

(iii) Eni SpA — Public Prosecutor of Milan — Insider trading. In March 2019, a request for extending certain investigations was notified to Eni's Chief Upstream Officer by the public prosecutor office of Milan. The commencement of those investigation was otherwise not notified. The investigations related to an alleged breach of Italian provisions that regulate insider trading and access to market-sensitive information. The breach was allegedly made from November 1 to December 1, 2016. There were no more informative details about the alleged breach in the notified document.

5. Settled Proceedings

(i) Syndial SpA — Clorosoda. The proceeding, involving 17 former managers of the Eni Group, regards alleged crimes of culpable manslaughter and grievous bodily harm related to the death of 12 former employees and alleged work-related diseases that those persons may have contracted at the plant of Clorosoda. Alleged crimes relate to the period from 1969, when the Clorosoda plant commenced operations, until 1998 when the plant was shut down and clean-up activities were performed. The Public Prosecutor requested a medical appraisal on over 100 people, who had been employed at the plant. This appraisal was performed by independent consultants designated by the Judge for preliminary investigation and did not find any evidence that the various diseases identified from the medical appraisal could be directly linked to the exposure to emissions related to the production of chlorine and caustic soda. The consultants also found that production activities were in compliance with applicable laws and regulations on health and safety. Following the outcome of the assessment, the Public Prosecutor of Gela issued a notice of conclusion of preliminary investigations in relation to 4 cases, contesting personal injuries and claimed the indictment only in one case concerning a worker who died in the meantime. Therefore, compared to the initial claim that concerned several (more than one hundred) cases of personal injury and manslaughter, the proceeding was narrowed. In June 2017, the Judge issued a ruling of nonsuit because the case was judged groundless. The Public Prosecutor appealed the first-degree sentence. In September 2018, the Second Instance Court in its final decision did not accept the appeal presented by the Public Prosecutor. Also for the proceeding concerning the four cases that are part of a separate proceeding, the Judge issued a ruling of nonsuit, which became irrevocable in February 2018.

(ii) Eni SpA-Raffineria di Gela SpA-Eni Mediterranea Idrocarburi SpA- Syndial SpA. In December 2015, 273 Gela residents filed an appeal to the Court of Gela requesting to halt all the production activities conducted by Eni's subsidiaries at Gela site in order to put an end to alleged environmental pollution affecting the health of the local population. The claimants also requested the appointment of commissioners in charge of carrying out the plant shutdown and of continuing implementing of clean-up activities in the area. They also requested the Court to order the Municipality of Gela — as a competent body in the field of health protection — to adopt certain provisions aimed to preserve the health of the local population. This proceeding arose in connection with alleged environmental damage caused by the industrial activities of the site and consequent necessity to protect the population from serious harm to the health. The initiative was carried out by certain technical assessments performed by consultants appointed by the Court in the preliminary stage. The aim of these assessments was to establish cause-and-effect relationships between the industrial contamination and congenital anomalies reported in the town of Gela. Following the outcome of the investigation, in December 2017 the Court of Gela rejected all the claims of the plaintiffs and ordered them to pay the expenses of the proceeding. The plaintiffs appealed the decision. In September 2018, the Court rejected the appeal presented by the appellants, confirming the order issued by the First Instance Court. The precautionary procedure promoted is therefore definitively concluded.

Assets under concession arrangements

Eni operates under concession arrangements mainly in the Exploration & Production segment and the Refining & Marketing business line. In the Exploration & Production segment, contractual clauses governing mineral concessions, licenses and exploration permits regulate the access of Eni to hydrocarbon reserves. Such clauses can differ in each country. In particular, mineral concessions, licenses and permits are granted by the legal owners and, generally, entered into with government entities, State oil companies and, in some legal contexts, private owners. Pursuant to the assignment of mineral concession, Eni sustains all the operational risks and costs related to the exploration and development activities and it is entitled to the productions realized. As a compensation for mineral concessions, Eni pays royalties and taxes in accordance with local tax legislation. In production sharing agreement and service contracts, realized productions are defined based on contractual agreements with State oil companies, which hold the concessions. Such contractual agreements regulate the recovery of costs incurred for the exploration, development and operating activities (Cost Oil) and give entitlement to the own portion of the realized productions (Profit Oil). In the Refining & Marketing business line, several service stations and other auxiliary assets of the distribution service are located in the motorway areas and they are granted by the motorway concession operators following a public tender for the sub-concession of the supplying of oil products distribution service and other auxiliary services. In exchange of the granting of the services described above, Eni provides to the motorway companies fixed and variable royalties based on quantities sold. At the end of the concession period, all non-removable assets are transferred to the grantor of the concession for no consideration.

Environmental regulations

Risks associated with the footprint of Eni's activities on the environment, health and safety are described in the "Financial Review", paragraph "Risk factors and uncertainties". In the future, Eni will sustain significant expenses in relation to compliance with environmental, health and safety laws and regulations and for reclaiming, safety and remediation works of areas previously used for industrial production and dismantled sites. In particular, regarding the environmental risk, management does not currently expect any material adverse effect upon Eni's Consolidated Financial Statements, taking account of ongoing remediation actions, existing insurance policies and the environmental risk provision accrued in the Consolidated Financial Statements. However, management believes that it is possible that Eni may incur material losses and liabilities in future years in connection with environmental matters due to: (i) the possibility of as yet unknown contamination; (ii) the results of ongoing surveys and other possible effects of statements required by Legislative Decree 152/2006; (iii) new developments in environmental regulation (i.e. Law No. 68/2015 on crimes against the environment and European Directive 2015/2193 on medium combustion plants); (iv) the effect of possible technological changes relating to future remediation; and (v) the possibility of litigation and the difficulty of determining Eni's liability, if any, as against other potentially responsible parties with respect to such litigation and the possible insurance recoveries.

Emission trading

From 2013, the third phase of the European Union Emissions Trading Scheme (EU-ETS) came in force. The new phase marked a significant change in the method of awarding emission allowance from a no-consideration scheme based on historical emissions to allocation through auctioning. For the period 2013 – 2020, the award of free emission allowances is performed based on European benchmarks specific to each industrial segment, except for the thermoelectric sector that is not eligible for allocations for no consideration. This regulatory scheme implies for Eni's plants subjected to emission trading a lower assignment of emission permits respect to the emissions recorded in the relevant year and, consequently, the necessity of covering the amounts in excess by purchasing the relevant emission allowances on the open market. In 2018, the emissions of carbon dioxide from Eni's plants were higher than the free allowances assigned to Eni. Against emissions of carbon dioxide amounting to approximately 19.93 million tonnes, Eni was awarded free emission allowances of 7.25 million tonnes, determining a deficit of 12.68 million tonnes. This deficit was entirely covered through the purchase of emission allowances in the open market.

28 Revenues

Net sales from operations

(€ million)	Exploration & Production	Gas & Power	Refining & Marketing and Chemical	Corporate and other activities	Total
2018					
Revenues from customers	9,943	43,109	22,594	176	**75,822**
Products sales and service revenues					
Sales of crude oil	3,982	18,471			**22,453**
Sales of oil products	1,133	4,053	17,213		**22,399**
Sales of natural gas and LNG	4,554	15,088			**19,642**
Sales of chemical products		762	4,777	35	**5,574**
Sales of other products	27	2,363	20	11	**2,421**
Services	247	2,372	584	130	**3,333**
Total	**9,943**	**43,109**	**22,594**	**176**	**75,822**
Transfer of goods and/or services					
Goods/Services transferred in a specific moment	9,676	42,979	22,535	106	**75,296**
Goods/Services transferred over a period of time	267	130	59	70	**526**

(€ million)	2018
Revenues associated with liabilities from customer contracts at the beginning of the period	**342**
Revenues associated with performance obligations totally or partially satisfied in previous years	**11**

Net sales from operations by industry segment and geographical area of destination are disclosed in note 35 — Segment information and information by geographical area.

Net sales from operations with related parties are disclosed in note 36 — Transactions with related parties.

Other income and revenues

(€ million)	2018	2017	2016
Gains from sale of assets and businesses	454	3,288	14
Other proceeds	662	770	917
	1,116	**4,058**	**931**

Gains from the sale of assets and businesses related to the divestment of a 10% stake in the Zohr project for €428 million. In 2017 the amount related to the divestment of a 25% stake in natural gas-rich Area 4 offshore Mozambique (€1,985 million) and of a 40% stake in the Zohr project (€1,281 million).

Other income and revenues with related parties are disclosed in note 36 — Transactions with related parties.

29 Costs

Purchase, services and other

(€ million)	2018	2017	2016
Production costs - raw, ancillary and consumable materials and goods	41,125	35,907	27,783
Production costs - services	10,625	12,228	12,727
Operating leases and other	1,820	1,684	1,672
Net provisions for contingencies	1,120	886	505
Expenses for price variation on overliftling and underlifting operations		145	240
Other expenses	1,130	931	666
	55,820	**51,781**	**43,593**
less:			
- capitalized direct costs associated with self-constructed assets - tangible assets	(192)	(224)	(297)
- capitalized direct costs associated with self-constructed assets - intangible assets	(6)	(9)	(18)
	55,622	**51,548**	**43,278**

Purchase, services and other charges include costs of geological and geophysical studies for €287 million (€273 million and €204 million in 2017 and 2016, respectively) and operating leases for €872 million (€1,022 million and €566 million in 2017 and 2016, respectively).

Costs incurred in connection with research and development activities expensed through profit and loss, as they did not meet the requirements to be recognized as long-lived assets, amounted to €197 million (€185 million and €161 million in 2017 and 2016, respectively).

Royalties on the extraction of hydrocarbons amounted to €1,043 million (€674 million and €572 million in 2017 and 2016, respectively).

Future minimum lease payments expected to be paid under non-cancelable operating leases are provided below:

(€ million)	2018	2017	2016
To be paid:			
- within 1 year	776	883	593
- between 2 and 5 years	1,653	1,710	1,040
- beyond 5 years	1,524	1,939	785
	3,953	**4,532**	**2,418**

Operating leases primarily comprised long-term rentals of FPSO vessels, offshore drilling rigs, time charter and land, service stations and office buildings. Such leases may not include renewal options. There are no significant restrictions provided by these operating leases that may limit the ability of Eni to pay dividends, use assets or take on new borrowing.

Additions to provisions for contingencies net of reversal of unused provisions related to net addition for litigations amounting to €101 million (net provisions of €375 million and €55 million in 2017 and 2016, respectively) and net additions for environmental liabilities amounting to €266 million (net provisions of €200 million and €198 million in 2017 and 2016, respectively). More information is provided in note 20 — Provisions for contingencies. Net provisions for contingencies by segment are disclosed in note 35 — Segment information and information by geographical area.

Payroll and related costs

(€ million)	2018	2017	2016
Wages and salaries	2,409	2,447	2,491
Social security contributions	448	441	445
Cost related to employee benefit plans	220	113	81
Other costs	170	162	202
	3,247	**3,163**	**3,219**
less:			
- capitalized direct costs associated with self-constructed assets - tangible assets	(142)	(202)	(215)
- capitalized direct costs associated with self-constructed assets - intangible assets	(12)	(10)	(10)
	3,093	**2,951**	**2,994**

Other costs comprised provisions for redundancy incentives of €37 million (€18 million and €47 million in 2017 and 2016, respectively) and costs for defined contribution plans of €95 million (€90 million and €83 million in 2017 and 2016, respectively).

Cost related to employee benefit plans are described in note 21 — Provisions for employee benefits.

Costs with related parties are disclosed in note 36 — Transactions with related parties.

Average number of employees

The Group average number and breakdown of employees by category is reported below:

	2018		2017		2016	
(number)	Subsidiaries	Joint operations	Subsidiaries	Joint operations	Subsidiaries	Joint operations
Senior managers	999	17	995	17	1,018	18
Junior managers	9,095	84	9,089	98	9,160	109
Employees	16,220	361	16,721	371	17,180	384
Workers	5,259	283	5,659	285	5,703	294
	31,573	**745**	**32,464**	**771**	**33,061**	**805**

The average number of employees was calculated as the average between the number of employees at the beginning and the end of the period. The average number of senior managers included managers employed in foreign countries, whose position is comparable to a senior manager's status.

Long-term monetary incentive plan for the managers of Eni

On April 13, 2017, the Shareholders Meeting approved the Long-Term Monetary Incentive Plan 2017 – 2019 and empowered the Board of Directors to execute the Plan by authorizing it to dispose up to a maximum of 11 million of treasury shares in service of the Plan.

The Long-Term Monetary Incentive Plan 2017 – 2019 provides for three annual awards for the years 2017, 2018 and 2019 and is intended for the Chief Executive Officer of Eni and for the managers of Eni and its subsidiaries who qualify as "senior managers deemed critical for the business", selected among those who are in charge of tasks directly linked to the Group results or of strategic interest to the business. The Plan provides the granting of Eni shares for no consideration to eligible managers after a three-year vesting period under the condition that they would remain in service until vesting. Considering that this incentive falls within the category of employee compensation, in accordance with IFRS, the cost of the plan is determined based on the fair value of the financial instruments awarded to the beneficiaries and the number of shares that will be granted at the end of the vesting period; the cost is accruing along the vesting period.

The number of shares that will be granted at the end of the vesting period is conditioned on a 50-50 basis to actual results of two performance parameters against preset targets: (i) a market condition in terms of Total Shareholder Return (TSR) of the Eni share compared to the TSR of the FTSE Mib index of the Italian Stock Exchange Market, and to a group of Eni's competitors ("Peers Group")[28] and the TSR of their corresponding stock exchange market[29]; (ii) growth in the Net Present Value (NPV) of proved reserves benchmarked against the Peer Group.

Depending on the performance of the parameters mentioned above, the number of shares that will vest after three years may range between 0% and 180% of the initial award. Furthermore, 50% of the shares that will eventually vest is subject to a lock-up clause of one year after the vesting date.

At the grant date, the number of shares awarded was 1,517,975 and 1,719,061 respectively in 2018 and in 2017; the weighted average fair value of the shares at the same date was €11.73 and €7.99 per share.

The determination of the fair value was calculated by adopting specific valuation techniques regarding the different performance parameters provided by the plan (the stochastic method for the market condition of the plan and the Black-Scholes model for the component related to the NPV of the reserves), taking into account the fair value of the Eni share at the grant date (€14.246 per share in 2018; €13.81 per share in 2017), reduced by dividends expected along the vesting period (5.8% of the share price at vesting date), the volatility of the stock (20% for attribution 2018; 25% for attribution 2017), the forecasts for the performance parameters, as well as the lower value attributable to the shares considering the lock-up period at the end of the vesting period.

In 2018, the costs related to the long-term monetary incentive plan 2017 – 2019, recognized as a component of the payroll cost, amounted to €5.1 million (€0.4 million in 2017) with a contra-entry to equity reserves.

Compensation of key management personnel

Compensation (including contributions and ancillary costs) of personnel holding key positions in planning, directing and controlling the Eni Group subsidiaries, including executive and non-executive officers, general managers and managers with strategic responsibilities in service during the year consisted of the following:

(€ million)	2018	2017	2016
Wages and salaries	27	25	26
Post-employment benefits	2	2	2
Other long-term benefits	10	9	12
Indemnities upon termination of employment		7	4
	39	**43**	**44**

Compensation of Directors and Statutory Auditors

Compensation of Directors amounted to €9.6 million, €14.5 million and €7.1 million for 2018, 2017 and 2016, respectively. Compensation of Statutory Auditors amounted to €0.604 million, €0.760 million and €0.738 million in 2018, 2017 and 2016, respectively.

[28] The group consists of the following oil companies: Anadarko, Apache, BP, Chevron, ConocoPhillips, ExxonMobil, Marathon Oil, Royal Dutch Shell, Statoil and Total.

[29] The performance condition connected with the TSR in accordance with the international accounting standards represents a so-called market condition.

Compensation included emoluments and social security benefits due for the office as Director or Statutory Auditor held at the parent company Eni SpA or other Group subsidiaries, which was recognized as a cost to the Group, even if not subject to personal income tax.

30 Finance income (expense)

(€ million)	2018	2017	2016
Finance income (expense)			
Finance income	3,967	3,924	5,850
Finance expense	(4,663)	(5,886)	(6,232)
Net finance income (expense) from financial assets held for trading	32	(111)	(21)
Income (expense) from derivative financial instruments	(307)	837	(482)
	(971)	**(1,236)**	**(885)**

The analysis of finance income (expense) was as follows:

(€ million)	2018	2017	2016
Finance income (expense) related to net borrowings			
Interest and other finance expense on ordinary bonds	(565)	(638)	(639)
Net finance income (expense) on financial assets held for trading	32	(111)	(21)
Interest due to banks and other financial institutions	(120)	(113)	(118)
Interest and other income on financial receivables and securities held for non-operating purposes	8	16	37
Interest from banks	18	12	15
	(627)	**(834)**	**(726)**
Exchange differences	**341**	**(905)**	**676**
Income (expense) from derivative financial instruments	**(307)**	**837**	**(482)**
Other finance income (expense)			
Interest and other income on financing receivables and securities held for operating purposes	132	128	143
Capitalized finance expense	52	73	106
Finance expense due to the passage of time (accretion discount)[a]	(249)	(264)	(312)
Other finance income (expense)	(313)	(271)	(290)
	(378)	**(334)**	**(353)**
	(971)	**(1,236)**	**(885)**

(a) The item related to the increase in provisions for contingencies that are shown at present value in non-current liabilities.

The analisys of derivative financial income (expense) is disclosed in note 23 — Derivative financial instruments and hedge accounting.

Finance income (expense) with related parties are disclosed in note 36 — Transactions with related parties.

31 Income (expense) from investments

Share of profit (loss) of equity-accounted investments

More information is provided in note 14 — Investments.

Share of profit or loss of equity accounted investments by segment is disclosed in note 35 — Segment information and information by geographical area.

Other gain (loss) from investments

(€ million)	2018	2017	2016
Dividends	231	205	143
Net gain (loss) on disposals	22	163	(14)
Other net income (expense)	910	(33)	(183)
	1,163	**335**	**(54)**

Dividend income related to Nigeria LNG Ltd for €187 million and to Saudi European Petrochemical Co for €35 million (similarly in the comparative periods).

Other net income included the gain of €889 million deriving from the business combination between Eni Norge AS and Point Resources AS, fully-owned respectively by Eni and HitecVision AS, with the establishment of the joint venture Vår Energi AS, jointly controlled by the two shareholders (Eni's interest 69.60%) and was determined as difference between the carrying amount of the equity investment, corresponding to the fair value of the combined net assets, and the book value of the divested net assets. In the comparative periods the expenses referred to the impairments of joint ventures and associates.

32 Income taxes

(€ million)	2018	2017	2016
Current taxes:			
- Italian subsidiaries	301	712	195
- subsidiaries of the Exploration & Production segment - outside Italy	4,906	3,167	2,671
- other subsidiaries - outside Italy	163	142	133
	5,370	**4,021**	**2,999**
Net deferred taxes:			
- Italian subsidiaries	130	(464)	(243)
- subsidiaries of the Exploration & Production segment - outside Italy	497	(162)	(813)
- other subsidiaries - outside Italy	(27)	72	(7)
	600	**(554)**	**(1,063)**
	5,970	**3,467**	**1,936**

Current income taxes payable by Italian subsidiaries referred to foreign taxes for €241 million.

The reconciliation between the statutory tax charge calculated by applying the Italian statutory tax rate of 24% (24% in 2017 and 27.5% in 2016) and the effective tax charge is the following:

(€ million)	2018	2017	2016
Profit (loss) before taxation	**10,107**	**6,844**	**892**
Tax rate (IRES) (%)	24.0	24.0	27.5
Statutory corporation tax charge (credit) on profit or loss	**2,426**	**1,643**	**245**
Increase (decrease) resulting from:			
- higher tax charges related to subsidiaries outside Italy	3,096	1,882	1,152
- impact pursuant to the write-off of deferred tax assets and recalculation of tax rates	252	(96)	397
- effect due to the tax regime provided for intercompany dividends	47	1	87
- Italian regional income tax (IRAP)	50	77	42
- effect due to non-taxable gains/losses on sales of investments	(1)	(177)	8
- impact pursuant to redetermination of the Italian Windfall Corporate tax as per Law 7/2009		61	
- other adjustments	100	76	5
	3,544	**1,824**	**1,691**
Effective tax charge	**5,970**	**3,467**	**1,936**

The higher tax charges at non-Italian subsidiaries €related to the Exploration & Production segment for €3,014 million (€1,811 million and €1,211 million in 2017 and in 2016, respectively).

33 Earnings per share

Basic earnings per ordinary share are calculated by dividing net profit for the period attributable to Eni's shareholders by the weighted average number of ordinary shares issued and outstanding during the period, excluding treasury shares.

The average number of ordinary shares used for the calculation of the basic earnings per share in 2018 was 3,601,140,133 (same amount in 2017 and 2016).

Diluted earnings per share is calculated by dividing the net profit of the period attributable to Eni's shareholders by the weighted average number of shares fully-diluted including shares outstanding in the year and the number of potential shares to be issued in connection with stock-based compensation plans.

As of December 31, 2018, the shares that could be potentially issued related the estimation of new share that will vest in connection with the long-term monetary incentive plan. The weighted average number of outstanding shares used for calculating the diluted earnings per share is 2,782,584 for 2018 (1,691,413 for 2017). In 2016, there were no potential shares with dilutive effects.

Reconciliation of the weighted average number of shares used for the calculation for both basic and diluted earnings per share was as follows:

		2018	2017	2016
Weighted average number of shares used for the calculation of the basic earnings per share		**3,601,140,133**	**3,601,140,133**	**3,601,140,133**
Potential share to be issued for ILT incentive plan		2,782,584	1,691,413	
Weighted average number of shares used for the calculation of the diluted earnings per share		**3,603,922,717**	**3,602,831,546**	**3,601,140,133**
Eni's net profit	(€ million)	**4,126**	**3,374**	**(1,464)**
Basic earning (loss) per share	(euro per share)	1.15	0.94	(0.41)
Diluted earning (loss) per share	(euro per share)	1.15	0.94	(0.41)
Eni's net profit – Continuing operations	(€ million)	**4,126**	**3,374**	**(1,051)**
Basic earning (loss) per share	(euro per share)	1.15	0.94	(0.29)
Diluted earning (loss) per share	(euro per share)	1.15	0.94	(0.29)
Eni's net profit – Discontinued operations	(€ million)			**(413)**
Basic earning (loss) per share	(euro per share)			(0.12)
Diluted earning (loss) per share	(euro per share)			(0.12)

34 Exploration for evaluation of oil&gas resources

(€ million)	2018	2017	2016
Revenues related to exploration activity and evaluation	**17**	**9**	**4**
Exploration activity and evaluation costs			
- write-off of exploration and evaluation costs	93	252	170
- costs of geological and geophysical studies	287	273	204
Exploration expense for the year	**380**	**525**	**374**
Intangible assets: proved and unproved exploration licence and leasehold property acquisition costs	1,081	995	1,092
Tangible assets: capitalized exploration and evaluation costs	1,267	1,371	1,905
Total tangible and intangible assets	**2,348**	**2,366**	**2,997**
Provision for decommissioning related to exploration activity and evaluation	**77**	**81**	**118**
Exploration expenditure (net cash used in investing activivties)	463	442	417
Geological and geophysical costs (cash flow from operating activities)	287	273	204
Total exploration effort	**750**	**715**	**621**

35 Segment information and information by geographical area

Segment information

Eni's segmental reporting reflects the Group's operating segments, whose results are regularly reviewed by the chief operating decision maker (the CEO) to make decisions about resources to be allocated to each segment and to assess segment performance.

Segment performance is evaluated based on operating profit or loss. Other segment information presented to the CEO include segment revenues and directly attributable assets and liabilities.

As of December 31, 2018, Eni had the following reportable segments:

- **Exploration & Production:** engages in the exploration, development and production of crude oil, LNG and natural gas, including projects to build and operate liquefaction plants of natural gas;
- **Gas & Power:** engages in supply and marketing of natural gas at wholesale and retail markets, supply and marketing of LNG and supply, production and marketing of power at retail and wholesale markets. Gas & Power is engaged in supply and marketing of crude oil and oil products targeting the operational requirements of Eni's refining business and in commodity trading (including crude oil, natural gas, oil products, power, emission allowances, etc.) targeting to both hedge and stabilize the Group industrial and commercial margins according to an integrated view and to optimize margins.
- **Refining & Marketing and Chemical:** engages in the manufacturing, supply and distribution and marketing activities of oil products and chemical products. The results of the Chemicals business have been aggregated to those of the Refining & Marketing business in a single reportable segment, because these two operating segments exhibit similar economic characteristics.
- **Corporate and other activities:** include the costs of the Group HQ functions which provide services to the operating subsidiaries, comprising holding, financing and treasury, IT, HR, real estate, legal assistance, captive insurance, planning and administration activities, as well as the results of the Group environmental cleanup and remediation activities performed by the subsidiary Syndial. The Energy Solutions Department, which engages in developing the business of renewable energy, is an operating segment, which is reported within Corporate and other activities because it does not meet the materiality threshold for separate segment reporting.

Information by segment is as follows:

(€ million)	Exploration & Production	Gas & Power	Refining & Marketing and Chemical	Corporate and other activities	Adjustments of intragroup profits	Total
2018						
Net sales from operations[(a)]	25,744	55,690	25,216	1,589		
Less: intersegment sales	(15,801)	(12,581)	(2,622)	(1,413)		
Net sales to customers	9,943	43,109	22,594	176		75,822
Operating profit	10,214	629	(380)	(691)	211	9,983
Net provisions for contingencies	235	53	274	579	(21)	1,120
Depreciation and amortization	6,152	408	399	59	(30)	6,988
Impairments of tangible and intangible assets	1,025	56	193	18		1,292
Reversals of tangible and intangible assets	299	127				426
Write-off	97	1	2			100
Share of profit (loss) of equity-accounted investments	158	9	(67)	(168)		(68)
Identifiable assets[(b)]	63,051	9,989	11,692	1,171	(420)	85,483
Unallocated assets						32,890
Equity-accounted investments	4,972	494	275	1,303		7,044
Identifiable liabilities[(c)]	18,110	8,314	4,319	4,072	(275)	34,540
Unallocated liabilities						32,760
Capital expenditure in tangible and intangible assets	7,901	215	877	143	(17)	9,119
2017						
Net sales from operations[(a)]	19,525	50,623	22,107	1,462		
Less: intersegment sales	(12,394)	(10,777)	(2,336)	(1,291)		
Net sales to customers	7,131	39,846	19,771	171		66,919
Operating profit	7,651	75	981	(668)	(27)	8,012
Net provisions for contingencies	479	(20)	182	245		886
Depreciation and amortization	6,747	345	360	60	(29)	7,483
Impairments of tangible and intangible assets	650	56	131	25		862
Reversals of tangible and intangible assets	808	202	77			1,087
Write-off	260	2	1			263
Share of profit (loss) of equity-accounted investments	(99)	(10)	(57)	(101)		(267)
Identifiable assets[(b)]	66,661	11,058	11,599	1,108	(610)	89,816
Unallocated assets						25,112
Equity-accounted investments	1,234	509	321	1,447		3,511
Identifiable liabilities[(c)]	17,273	8,851	4,005	4,053	(306)	33,876
Unallocated liabilities						32,973
Capital expenditure in tangible and intangible assets	7,739	142	729	87	(16)	8,681
2016						
Net sales from operations[(a)]	16,089	40,961	18,733	1,343		
Less: intersegment sales	(9,711)	(8,898)	(1,605)	(1,150)		
Net sales to customers	6,378	32,063	17,128	193		55,762
Operating profit	2,567	(391)	723	(681)	(61)	2,157
Net provisions for contingencies	123	50	171	438	(277)	505
Depreciation and amortization	6,772	354	389	72	(28)	7,559
Impairments of tangible and intangible assets	740	167	120	40		1,067
Reversals of tangible and intangible assets	1,440	86	16			1,542
Write-off	153	2	195			350
Share of profit (loss) of equity-accounted investments	(198)	19	(3)	(144)		(326)
Identifiable assets[(b)]	75,716	12,014	10,712	1,146	(520)	99,068
Unallocated assets						25,477
Equity-accounted investments	1,626	592	289	1,533		4,040
Identifiable liabilities[(c)]	17,433	8,923	3,968	3,939	(332)	33,931
Unallocated liabilities						37,528
Capital expenditure in tangible and intangible assets	8,254	120	664	55	87	9,180

(a) Before elimination of intersegment sales.
(b) Includes assets directly associated with the generation of operating profit.
(c) Includes liabilities directly associated with the generation of operating profit.

Financial information by geographical area

Identifiable assets and investments by geographical area of origin

(€ million)	Italy	Other European Union	Rest of Europe	Americas	Asia	Africa	Other areas	Total
2018								
Identifiable assets[(a)]	18,646	7,086	1,031	4,546	16,910	36,155	1,109	85,483
Capital expenditure in tangible and intangible assets	1,424	267	538	534	1,782	4,533	41	9,119
2017								
Identifiable assets[(a)]	18,449	7,706	6,160	4,406	16,527	35,385	1,183	89,816
Capital expenditure in tangible and intangible assets	1,090	316	387	278	898	5,699	13	8,681
2016								
Identifiable assets[(a)]	18,769	7,370	6,960	5,397	19,471	39,812	1,289	99,068
Capital expenditure in tangible and intangible assets	1,163	331	460	233	1,978	5,004	11	9,180

(a) Includes assets directly associated with the generation of operating profit.

Net sales from operations by geographical area of destination

(€ million)	2018	2017	2016
Italy	25,279	21,925	21,280
Other European Union	20,408	19,791	15,808
Rest of Europe	7,052	5,911	4,804
Americas	5,051	5,154	3,212
Asia	9,585	7,523	5,619
Africa	8,246	6,428	4,865
Other areas	201	187	174
	75,822	**66,919**	**55,762**

36 Transactions with related parties

In the ordinary course of its business, Eni enters into transactions with related parties regarding:

(a) exchange of goods, provision of services and financing with joint ventures, associates and non-consolidated subsidiaries;

(b) exchange of goods and provision of services with entities controlled by the Italian Government;

(c) exchange of goods and provision of services with companies related to Eni SpA through members of the Board of Directors. Most of these transactions are exempt from the application of the Eni internal procedure of Eni "Transactions involving interests of Directors and Statutory Auditors and transactions with related parties" pursuant to the Consob Regulation, since they relate to ordinary transactions conducted at market or standard conditions, or because under the materiality threshold provided for by the procedure. The solely non-exempted transaction, that was positively examined and valued in application of the procedure, concerned the remote monitoring of cars in the "Enjoy" initiative (for an amount of lower than €1 million) conducted with Vodafone Italia SpA related to Eni SpA through of a member of the Board of Directors;

(d) contributions to non-profit entities correlated to Eni with the aim to develop solidarity, culture and research initiatives. In particular these related to: (i) Eni Foundation established by Eni as a non-profit entity with the aim of pursuing exclusively solidarity initiatives in the fields of social assistance, health, education, culture and environment, as well as scientific and technological research; and (ii) Eni Enrico Mattei Foundation established by Eni with the aim of enhancing, through studies, research and training initiatives, knowledge in the fields of economics, energy and environment, both at the national and international level.

Some low transactions with companies related to Eni SpA through some members of the Board of Directors were concluded at market or standard conditions, or in compliance with Eni's internal procedure "Transactions involving interests of Directors and Statutory Auditors and transactions with related parties", pursuant the Consob regulation.

Transactions with related parties were conducted in the interest of Eni companies and, with exception of those with entities whose aim is to develop charitable, cultural and research initiatives, are related to the ordinary course of Eni's business.

Trade and other transactions with related parties

(€ million)

Name	December 31, 2018 Receivables and other assets	Payables and other liabilities	Guarantees	2018 Costs	Revenues	Other operating (expense) income
Joint ventures and associates						
Agiba Petroleum Co	1	96		156		
Angola LNG Supply Services Llc			177			
Coral FLNG SA	14		1,147		62	
Gas Distribution Company of Thessaloniki - Thessaly SA	1	18		51		
Karachaganak Petroleum Operating BV	27	134		998	1	
Mellitah Oil & Gas BV	1	268		502	1	
Petrobel Belayim Petroleum Co	56	2,029		2,282	7	
Saipem Group	75	171	793	420	30	
Unión Fenosa Gas SA	4	7	57		123	37
Vår Energi AS	13	100	218			
Other (*)	44	25		104	111	(26)
	236	**2,848**	**2,392**	**4,513**	**335**	**11**
Unconsolidated entities controlled by Eni						
Eni BTC Ltd			177			
Industria Siciliana Acido Fosforico - ISAF SpA (in liquidation)	87	1	5		11	
Other	6	23	14	13	7	
	93	**24**	**196**	**13**	**18**	
	329	**2,872**	**2,588**	**4,526**	**353**	**11**
Entities controlled by the Government						
Enel Group	134	151		514	118	227
GSE - Gestore Servizi Energetici	67	85		588	555	74
Italgas Group	5	146		667	23	
Snam Group	237	289		1,184	109	(1)
Terna Group	26	47		231	150	8
Other	25	18		34	45	
	494	**736**		**3,218**	**1,000**	**308**
Other related parties	**1**	**2**		**32**	**4**	
Groupement Sonatrach - Agip «GSA» and Organe Conjoint des Opérations «OC SH/FCP»	**40**	**140**		**229**	**34**	
Total	**864**	**3,750**	**2,588**	**8,005**	**1,391**	**319**

(*) Each individual amount included herein was lower than €50 million.

(€ million)

Name	December 31, 2017 Receivables and other assets	Payables and other liabilities	Guarantees	2017 Costs	Revenues	Other operating (expense) income
Joint ventures and associates						
Agiba Petroleum Co	1	83		142		
Coral FLNG SA	20	4	1,094		28	
Karachaganak Petroleum Operating BV	36	121		951		
Mellitah Oil & Gas BV	5	220		495	2	
Petrobel Belayim Petroleum Co	86	1,205		3,168	8	
Saipem Group	63	76	7,270	450	44	
Unión Fenosa Gas SA			57	3	202	28
Other (*)	84	22		140	128	
	295	**1,731**	**8,421**	**5,349**	**412**	**28**
Unconsolidated entities controlled by Eni						
Eni BTC Ltd			169			
Industria Siciliana Acido Fosforico - ISAF - SpA (in liquidation)	77	1	5		7	
Other	20	23	7	14	7	
	97	**24**	**181**	**14**	**14**	
	392	**1,755**	**8,602**	**5,363**	**426**	**28**
Entities controlled by the Government						
Enel Group	123	187		622	164	285
GSE - Gestore Servizi Energetici	69	219		506	702	2
Italgas Group	14	180	1	681	18	
Snam Group	187	351		1,221	85	
Terna Group	35	31		212	154	15
Other (*)	50	21		38	16	1
	478	**989**	**1**	**3,280**	**1,139**	**303**
Other related parties	**1**	**2**		**25**	**1**	
Groupement Sonatrach - Agip «GSA» and Organe Conjoint des Opérations «OC SH/FCP»	**39**	**145**		**530**	**42**	
Total	**910**	**2,891**	**8,603**	**9,198**	**1,608**	**331**

(*) Each individual amount included herein was lower than €50 million.

(€ million)

Name	December 31, 2016 Receivables and other assets	Payables and other liabilities	Guarantees	2016 Costs	Revenues	Other operating (expense) income
Joint ventures and associates						
Agiba Petroleum Co	1	50		156		
Karachaganak Petroleum Operating BV	47	187		918	27	
Mellitah Oil & Gas BV	7	134		477		
Petrobel Belayim Petroleum Co	225	532		1,940	2	
Saipem Group	64	224	8,094	781	51	
Unión Fenosa Gas SA			57		94	
Other(*)	114	25	1	145	143	47
	458	**1,152**	**8,152**	**4,417**	**317**	**47**
Unconsolidated entities controlled by Eni						
Eni BTC Ltd			192			
Industria Siciliana Acido Fosforico - ISAF - SpA (in liquidation)	69	1	3		2	
Other (*)	9	16	51	8	10	
	78	**17**	**246**	**8**	**12**	
	536	**1,169**	**8,398**	**4,425**	**329**	**47**
Entities controlled by the Government						
Enel Group	151	254		808	201	182
GSE - Gestore Servizi Energetici	58	32		243	414	5
Italgas Group	54	1		4		
Snam Group	44	541	1	2,032	113	
Terna Group	33	46		232	117	13
Other (*)	43	24		37	68	
	383	**898**	**1**	**3,356**	**913**	**200**
Other related parties		**2**		**32**		
Groupement Sonatrach - Agip «GSA» and Organe Conjoint des Opérations «OC SH/FCP»	**176**	**331**		**423**	**70**	
Total	**1,095**	**2,400**	**8,399**	**8,236**	**1,312**	**247**

(*) Each individual amount included herein was lower than €50 million.

The most significant transactions with joint ventures, associates and unconsolidated subsidiaries concerned:

- Eni's share of expenses incurred to develop oil fields from Agiba Petroleum Co, Karachaganak Petroleum Operating BV, Mellitah Oil & Gas BV, Petrobel Belayim Petroleum Co, Groupement Sonatrach — Agip «GSA», Organe Conjoint des Opérations «OC SH/FCP» and, only for Karachaganak Petroleum Operating BV, purchase of oil products by Eni Trading & Shipping SpA; services charged to Eni's associates are invoiced on the basis of incurred costs;
- guarantees issued on behalf of Angola LNG Supply Services Llc to cover the commitments relating to the payment of the regasification fees;
- supply of upstream specialist services and guarantees issued on a pro-quota basis granted to Coral FLNG SA on behalf of the Consortium TJS for the contractual obligations assumed following the award of the EPCIC contract for the construction of a floating gas liquefaction plant and the provision of services (for more information see note 27 — Guarantees, commitments and risks);
- the acquisition of transport and distribution services from Gas Distribution Company of Thessaloniki — Thessaly SA;
- engineering, construction and drilling services by Saipem Group mainly for the Exploration & Production segment and residual guarantees issued by Eni SpA relating to bid bonds and performance bonds;
- performance guarantees given on behalf of Unión Fenosa Gas SA in relation to contractual commitments related to the results of operations, sales of LNG and fair value of derivative financial instruments;
- guarantees issued in compliance with contractual agreements in the interest of Vår Energi AS and trade and other receivables and payables;
- a guarantee issued in relation to the construction of an oil pipeline on behalf of Eni BTC Ltd; and
- services for environmental restoration to Industria Siciliana Acido Fosforico — ISAF SpA (in liquidation).

The most significant transactions with entities controlled by the Italian Government concerned:

- sale of fuel, sale and purchase of gas, acquisition of power distribution services and fair value of derivative financial instruments with Enel Group;

- acquisition of natural gas transportation, distribution and storage services with the Snam Group and the Italgas Group on the basis of tariffs set by the Italian Regulatory Authority for Energy, Networks and Environment and purchase and sale of natural gas for granting the balancing of the system on the basis of prices referred to the quotations of the main energy commodities;
- sale and purchase of electricity, the acquisition of domestic electricity transmission service on the basis of prices referred to the quotations of the main energy commodities, and derivatives on commodities entered to hedge the price risk related to the utilization of transport capacity rights with the Terna Group;
- sale and purchase of electricity, gas, environmental certificates, fair value of derivative financial instruments and sale of oil products with GSE — Gestore Servizi Energetici for the setting-up of a specific stock held by the Organismo Centrale di Stoccaggio Italiano (OCSIT) according to the Legislative Decree No. 249/2012.

Transactions with other related parties concerned:

- provisions to pension funds of €24 million; and
- contributions and service provisions to Eni Foundation of €3 million and to Eni Enrico Mattei Foundation for €4 million.

Financing transactions with related parties

(€ million)

	December 31, 2018			2018	
Name	**Receivables**	**Payables**	**Guarantees**	**Charges**	**Gains**
Joint ventures and associates					
Angola LNG Ltd			245		
Cardón IV SA	705	36			95
Coral FLNG SA	108				
Coral South FLNG DMCC			1,397		
Shatskmorneftegaz Sàrl				267	7
Société Centrale Electrique du Congo SA	64	30		5	
Vår Energi AS		494			
Other	38	4	22	9	13
	915	**564**	**1,664**	**281**	**115**
Unconsolidated entities controlled by Eni					
Other	49	25			
	49	**25**			
Entities controlled by the Government					
Enel Group		64			
Other		8		2	
		72		**2**	
Total	**964**	**661**	**1,664**	**283**	**115**

(€ million)

	December 31, 2017			2017	
Name	**Receivables**	**Payables**	**Guarantees**	**Charges**	**Gains**
Joint ventures and associates					
Angola LNG Ltd			233		
Cardón IV SA	955				86
Coral FLNG SA	56				71
Coral South FLNG DMCC			1,334		
Saipem Group		3	56		13
Shatskmorneftegaz Sarl	101				6
Société Centrale Electrique du Congo SA	66	43			
Other	48	49	2	1	14
	1,226	**95**	**1,625**	**1**	**190**
Unconsolidated entities controlled by Eni					
Servizi Fondo Bombole Metano SpA	60	9			1
Other(*)	1	52			
	61	**61**			**1**
Entities controlled by the Government					
Other		8		3	
		8		**3**	
Total	**1,287**	**164**	**1,625**	**4**	**191**

(*) Each individual amount included herein was lower than €50 million.

(€ million)

Name	December 31, 2016 Receivables	Payables	Guarantees	2016 Charges	Gains	Derivative financial instruments
Joint ventures and associates						
Cardón IV SA	1,054				96	
Matrìca SpA	125			93	9	
Shatskmorneftegaz Sarl	69			13	4	
Société Centrale Electrique du Congo SA	78			18		
Unión Fenosa Gas SA		85				
Saipem Group			82		43	27
Other(*)	52		2	17	4	
	1,378	**85**	**84**	**141**	**156**	**27**
Unconsolidated entities controlled by Eni						
Eni BTC Ltd		54				
Other(*)	46	52		1	1	
	46	**106**		**1**	**1**	
Entities controlled by the Government						
Other				3		
				3		
Total	**1,424**	**191**	**84**	**145**	**157**	**27**

(*) Each individual amount included herein was lower than €50 million.

The most significant transactions with joint ventures, associates and unconsolidated subsidiaries concerned:

- bank debt guarantees issued on behalf of Angola LNG Ltd;
- financing loans granted to Cardón IV SA for the exploration and development activities of the Perla offshore gas field in Venezuela;
- financing loans granted to Coral FLNG SA for the construction of a floating gas liquefaction plant in the Area 4 in Mozambique (for more information see note 27 — Guarantees, commitments and risks);
- a bank debt guarantee issued on behalf of Coral South FLNG DMCC (for more information see note 27 — Guarantees, commitments and risks);
- the impairment of financial receivables granted to Shatskmorneftegaz Sàrl;
- the loan granted to Société Centrale Electrique du Congo SA for the construction of a power plant in Congo and a cash deposit at Eni's financial companies;
- a cash deposit held at Eni's financial companies by Vår Energi AS.

The most significant transactions with entities controlled by the Italian Government concerned:

- restricted deposits in escrow of derivative financial instruments with Enel Group.

Impact of transactions and positions with related parties on the balance sheet, profit and loss account and statement of cash flows

The impact of transactions and positions with related parties on the balance sheet consisted of the following:

(€ million)

	December 31, 2018 Total	Related parties	Impact %	December 31, 2017 Total	Related parties	Impact %
Other current financial assets	300	49	16.33	316	73	23.10
Trade and other receivables	14,101	633	4.49	15,421	834	5.41
Other current assets	2,258	71	3.14	1,573	30	1.91
Other non-current financial assets	1,253	915	73.02	1,675	1,214	72.48
Other non-current assets	792	160	20.20	1,323	46	3.48
Short-term debt	2,182	661	30.29	2,242	164	7.31
Trade and other payables	16,747	3,664	21.88	16,748	2,808	16.77
Other current liabilities	3,980	63	1.58	1,515	60	3.96
Other non-current liabilities	1,502	23	1.53	1,479	23	1.56

The impact of transactions with related parties on the profit and loss accounts consisted of the following:

	2018			2017			2016		
(€ million)	Total	Related parties	Impact %	Total	Related parties	Impact %	Total	Related parties	Impact %
Net sales from operations	75,822	1,383	1.82	66,919	1,567	2.34	55,762	1,238	2.22
Other income and revenues	1,116	8	0.72	4,058	41	1.01	931	74	7.95
Purchases, services and other	(55,622)	(8,009)	14.40	(51,548)	(9,164)	17.78	(43,278)	(8,212)	18.97
Net (impairment losses) reversals of trade and other receivables	(415)	26	—	(913)			(846)		
Payroll and related costs	(3,093)	(22)	0.71	(2,951)	(34)	1.15	(2,994)	(24)	0.80
Other operating income (expense)	129	319	—	(32)	331	—	16	247	—
Finance income	3,967	115	2.90	3,924	191	4.87	5,850	157	2.69
Finance expense	(4,663)	(283)	6.07	(5,886)	(4)	0.07	(6,232)	(145)	2.33
Derivative financial instruments	(307)			837			(482)	27	—

Main cash flows with related parties are provided below:

(€ million)	2018	2017	2016
Revenues and other income	1,391	1,608	1,312
Costs and other expenses	(5,210)	(5,360)	(5,623)
Other operating income (loss)	319	331	247
Net change in trade and other receivables and liabilities	683	391	182
Net interests	110	187	133
Net cash provided from operating activities	**(2,707)**	**(2,843)**	**(3,749)**
Capital expenditure in tangible and intangible assets	(2,768)	(3,838)	(2,613)
Disposal of investments			463
Net change in accounts payable and receivable in relation to investments	20	425	252
Change in financial receivables	(566)	298	5,650
Net cash used in investing activities	**(3,314)**	**(3,115)**	**3,752**
Change in financial liabilities	16	(16)	(192)
Net cash used in financing activities	**16**	**(16)**	**(192)**
Total financial flows to related parties	**(6,005)**	**(5,974)**	**(189)**

The impact of cash flows with related parties consisted of the following:

	2018			2017			2016		
(€ million)	Total	Related parties	Impact %	Total	Related parties	Impact %	Total	Related parties	Impact %
Cash provided from operating activities	13,647	(2,707)	—	10,117	(2,843)	—	7,673	(3,749)	—
Cash used in investing activities	(7,536)	(3,314)	43.98	(3,768)	(3,115)	82.67	(4,443)	3,752	—
Cash used in financing activities	(2,637)	16	—	(4,595)	(16)	0.35	(3,651)	(192)	5.26

37 Other information about investments

Information on Eni's investments as of December 31, 2018

The following section provides the information about Eni's subsidiaries, joint arrangements, associates and other significant investments as of December 31, 2018. Unless otherwise indicated, share capital is represented by ordinary shares directly held by the Group, while ownership interest corresponds to voting rights.

Parent company

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership
Eni SpA[(#)]	Rome	Italy	EUR	4,005,358,876	Cassa Depositi e Prestiti SpA Ministero dell'Economia e delle Finanze Eni SpA Other shareholders	25.76 4.34 0.91 68.99

Subsidiaries

Exploration & Production

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method[(*)]
Eni Angola SpA	San Donato Milanese (MI)	Angola	EUR	20,200,000	Eni SpA	100.00	100.00	F.C.
Eni Mediterranea Idrocarburi SpA	Gela (CL)	Italy	EUR	5,200,000	Eni SpA	100.00	100.00	F.C.
Eni Mozambico SpA	San Donato Milanese (MI)	Mozambique	EUR	200,000	Eni SpA	100.00	100.00	F.C.
Eni Timor Leste SpA	San Donato Milanese (MI)	East Timor	EUR	6,841,517	Eni SpA	100.00	100.00	F.C.
Eni West Africa SpA	San Donato Milanese (MI)	Angola	EUR	10,000,000	Eni SpA	100.00	100.00	F.C.
Eni Zubair SpA (in liquidation)	San Donato Milanese (MI)	Italy	EUR	120,000	Eni SpA	100.00		Co.
EniProgetti SpA	Venezia Marghera (VE)	Italy	EUR	2,064,000	Eni SpA	100.00	100.00	F.C.
Floaters SpA	San Donato Milanese (MI)	Italy	EUR	200,120,000	Eni SpA	100.00	100.00	F.C.
Ieoc SpA	San Donato Milanese (MI)	Egypt	EUR	7,518,000	Eni SpA	100.00	100.00	F.C.
Società Petrolifera Italiana SpA	San Donato Milanese (MI)	Italy	EUR	13,877,600	Eni SpA Third parties	99.96 0.04	99.96	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

(#) Company with shares quoted in the regulated market of Italy or of other EU countries

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Agip Caspian Sea BV	Amsterdam (Netherlands)	Kazakhstan	EUR	20,005	Eni International BV	100.00	100.00	F.C.
Agip Energy and Natural Resources (Nigeria) Ltd	Abuja (Nigeria)	Nigeria	NGN	5,000,000	Eni International BV Eni Oil Holdings BV	95.00 5.00	100.00	F.C.
Agip Karachaganak BV	Amsterdam (Netherlands)	Kazakhstan	EUR	20,005	Eni International BV	100.00	100.00	F.C.
Agip Oil Ecuador BV	Amsterdam (Netherlands)	Ecuador	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Agip Oleoducto de Crudos Pesados BV	Amsterdam (Netherlands)	Ecuador	EUR	20,000	Eni International BV	100.00		Eq.
Burren Energy (Bermuda) Ltd	Hamilton (Bermuda)	United Kingdom	USD	12,002	Burren Energy Plc	100.00	100.00	F.C.
Burren Energy (Egypt) Ltd	London (United Kingdom)	Egypt	GBP	2	Burren Energy Plc	100.00		Eq.
Burren Energy Congo Ltd	Tortola (British Virgin Islands)	Republic of the Congo	USD	50,000	Burren En.(Berm)Ltd	100.00	100.00	F.C.
Burren Energy India Ltd	London (United Kingdom)	United Kingdom	GBP	2	Burren Energy Plc	100.00	100.00	F.C.
Burren Energy Plc	London (United Kingdom)	United Kingdom	GBP	28,819,023	Eni UK Holding Plc Eni UK Ltd	99.99 (—)	100.00	F.C.
Burren Shakti Ltd	Hamilton (Bermuda)	United Kingdom	USD	65,300,000	Burren En. India Ltd	100.00	100.00	F.C.
Eni Abu Dhabi BV	Amsterdam (Netherlands)	United Arab Emirates	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni AEP Ltd	London (United Kingdom)	Pakistan	GBP	73,471,000	Eni UK Ltd	100.00	100.00	F.C.
Eni Algeria Exploration BV	Amsterdam (Netherlands)	Algeria	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Algeria Ltd Sàrl	Luxembourg (Luxembourg)	Algeria	USD	20,000	Eni Oil Holdings BV	100.00	100.00	F.C.
Eni Algeria Production BV	Amsterdam (Netherlands)	Algeria	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Ambalat Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni America Ltd	Dover, Delaware (USA)	USA	USD	72,000	Eni UHL Ltd	100.00	100.00	F.C.
Eni Angola Exploration BV	Amsterdam (Netherlands)	Angola	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Angola Production BV	Amsterdam (Netherlands)	Angola	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Argentina Exploración y Explotación SA	Buenos Aires (Argentina)	Argentina	ARS	24,136,336	Eni International BV Eni Oil Holdings BV	95.00 5.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni Arguni I Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Australia BV	Amsterdam (Netherlands)	Australia	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Australia Ltd	London (United Kingdom)	Australia	GBP	20,000,000	Eni International BV	100.00	100.00	F.C.
Eni Bahrain BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100,00		Eq.
Eni BB Petroleum Inc	Dover, Delaware (USA)	USA	USD	1,000	Eni Petroleum Co Inc	100.00	100.00	F.C.
Eni BTC Ltd	London (United Kingdom)	United Kingdom	GBP	23,214,400	Eni International BV	100.00		Eq.
Eni Bukat Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Bulungan BV	Amsterdam (Netherlands)	Indonesia	EUR	20,000	Eni International BV	100.00		Eq.
Eni Canada Holding Ltd	Calgary (Canada)	Canada	USD	1,453,200,001	Eni International BV	100.00	100.00	F.C.
Eni CBM Ltd	London (United Kingdom)	Indonesia	USD	2,210,728	Eni Lasmo Plc	100.00	100.00	F.C.
Eni China BV	Amsterdam (Netherlands)	China	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Congo SA	Pointe - Noire (Republic of the Congo)	Republic of the Congo	USD	17,000,000	Eni E&P Holding BV Eni Int. NA NV Sàrl Eni International BV	99.99 (—) (—)	100.00	F.C.
Eni Côte d'Ivoire Ltd	London (United Kingdom)	Ivory Coast	GBP	1	Eni UK Ltd	100.00	100.00	F.C.
Eni Cyprus Ltd	Nicosia (Cyprus)	Cyprus	EUR	2,006	Eni International BV	100.00	100.00	F.C.
Eni Denmark BV	Amsterdam (Netherlands)	Greenland	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni do Brasil Investimentos em Exploração e Produção de Petróleo Ltda	Rio de Janeiro (Brazil)	Brazil	BRL	1,593,415,000	Eni International BV Eni Oil Holdings BV	99.99 (—)		Eq.
Eni East Ganal Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni East Sepinggan Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Elgin/ Franklin Ltd	London (United Kingdom)	United Kingdom	GBP	100	Eni UK Ltd	100.00	100.00	F.C.
Eni Energy Russia BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Exploration & Production Holding BV	Amsterdam (Netherlands)	Netherlands	EUR	29,832,777.12	Eni International BV	100.00	100.00	F.C.
Eni Gabon SA	Libreville (Gabon)	Gabon	XAF	13,132,000,000	Eni International BV	100.00	100.00	F.C.
Eni Ganal Ltd	London (United Kingdom)	Indonesia	GBP	2	Eni Indonesia Ltd	100.00	100.00	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni Gas & Power LNG Australia BV	Amsterdam (Netherlands)	Australia	EUR	10,000,000	Eni International BV	100.00	100.00	F.C.
Eni Ghana Exploration and Production Ltd	Accra (Ghana)	Ghana	GHS	21,412,500	Eni International BV	100.00	100.00	F.C.
Eni Hewett Ltd	Aberdeen (United Kingdom)	United Kingdom	GBP	3,036,000	Eni UK Ltd	100.00	100.00	F.C.
Eni Hydrocarbons Venezuela Ltd	London (United Kingdom)	Venezuela	GBP	8,050,500	Eni Lasmo Plc	100.00	100.00	F.C.
Eni India Ltd	London (United Kingdom)	India	GBP	44,000,000	Eni UK Ltd	100.00	100.00	F.C.
Eni Indonesia Ltd	London (United Kingdom)	Indonesia	GBP	100	Eni ULX Ltd	100.00	100.00	F.C.
Eni Indonesia Ots 1 Ltd	Grand Cayman (Cayman Islands)	Indonesia	USD	1.01	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni International NA NV Sàrl	Luxembourg (Luxembourg)	United Kingdom	USD	25,000	Eni International BV	100.00	100.00	F.C.
Eni Investments Plc	London (United Kingdom)	United Kingdom	GBP	750,050,000	Eni SpA Eni UK Ltd	99.99 (—)	100.00	F.C.
Eni Iran BV	Amsterdam (Netherlands)	Iran	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Iraq BV	Amsterdam (Netherlands)	Iraq	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Ireland BV	Amsterdam (Netherlands)	Ireland	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Isatay BV	Amsterdam (Netherlands)	Kazakhstan	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni JPDA 03-13 Ltd	London (United Kingdom)	Australia	GBP	250,000	Eni International BV	100.00	100.00	F.C.
Eni JPDA 06-105 Pty Ltd	Perth (Australia)	Australia	AUD	80,830,576	Eni International BV	100.00	100.00	F.C.
Eni JPDA 11-106 BV	Amsterdam (Netherlands)	Australia	EUR	50,000	Eni International BV	100.00	100.00	F.C.
Eni Kenya BV	Amsterdam (Netherlands)	Kenya	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Krueng Mane Ltd	London (United Kingdom)	Indonesia	GBP	2	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Lasmo Plc	London (United Kingdom)	United Kingdom	GBP	337,638,724.25	Eni Investments Plc Eni UK Ltd	99.99 (—)	100.00	F.C.
Eni Lebanon BV	Amsterdam (Netherlands)	Lebanon	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Liberia BV	Amsterdam (Netherlands)	Liberia	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Liverpool Bay Operating Co Ltd	London (United Kingdom)	United Kingdom	GBP	1	Eni UK Ltd	100.00		Eq.
Eni LNS Ltd	London (United Kingdom)	United Kingdom	GBP	80,400,000	Eni UK Ltd	100.00	100.00	F.C.
Eni Marketing Inc	Dover, Delaware (USA)	USA	USD	1,000	Eni Petroleum Co Inc	100.00	100.00	F.C.
Eni Maroc BV	Amsterdam (Netherlands)	Morocco	EUR	20,000	Eni International BV	100.00	100.00	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni México S. de RL de CV	Lomas De Chapultepec, Mexico City (Mexico)	Mexico	MXN	3,000	Eni International BV Eni Oil Holdings BV	99.90 0.10	100.00	F.C.
Eni Middle East Ltd	London (United Kingdom)	United Kingdom	GBP	1	Eni ULT Ltd	100.00	100.00	F.C.
Eni MOG Ltd (in liquidation)	London (United Kingdom)	United Kingdom	GBP	220,711,147.50	Eni Lasmo Plc Eni LNS Ltd	99.99 (—)	100.00	F.C.
Eni Montenegro BV	Amsterdam (Netherlands)	Montenegro	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Mozambique Engineering Ltd	London (United Kingdom)	United Kingdom	GBP	1	Eni UK Ltd	100.00	100.00	F.C.
Eni Mozambique LNG Holding BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Muara Bakau BV	Amsterdam (Netherlands)	Indonesia	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Myanmar BV	Amsterdam (Netherlands)	Myanmar	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni North Africa BV	Amsterdam (Netherlands)	Libya	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni North Ganal Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Oil & Gas Inc	Dover, Delaware (USA)	USA	USD	100,800	Eni America Ltd	100.00	100.00	F.C.
Eni Oil Algeria Ltd	London (United Kingdom)	Algeria	GBP	1,000	Eni Lasmo Plc	100.00	100.00	F.C.
Eni Oil Holdings BV	Amsterdam (Netherlands)	Netherlands	EUR	450,000	Eni ULX Ltd	100.00	100.00	F.C.
Eni Oman BV	Amsterdam (Netherlands)	Oman	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Pakistan (M) Ltd Sàrl	Luxembourg (Luxembourg)	Pakistan	USD	20,000	Eni Oil Holdings BV	100.00	100.00	F.C.
Eni Pakistan Ltd	London (United Kingdom)	Pakistan	GBP	90,087	Eni ULX Ltd	100.00	100.00	F.C.
Eni Petroleum Co Inc	Dover, Delaware (USA)	USA	USD	156,600,000	Eni SpA Eni International BV	63.86 36.14	100.00	F.C.
Eni Petroleum US Llc	Dover, Delaware (USA)	USA	USD	1,000	Eni BB Petroleum Inc	100.00	100.00	F.C.
Eni Portugal BV	Amsterdam (Netherlands)	Portugal	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Rapak Ltd	London (United Kingdom)	Indonesia	GBP	2	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni RD Congo SA	Kinshasa (Democratic Republic of the Congo)	Democratic Republic of the Congo	CDF	750,000,000	Eni International BV Eni Oil Holdings BV	99.99 (—)		Eq.
Eni Rovuma Basin BV	Amsterdam (Netherlands)	Mozambique	EUR	20,000	Eni Mozambique LNG H. BV	100.00	100.00	F.C.
Eni Sharjah BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni South Africa BV	Amsterdam (Netherlands)	Republic of South Africa	EUR	20,000	Eni International BV	100.00	100.00	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni South China Sea Ltd Sàrl	Luxembourg (Luxembourg)	China	USD	20,000	Eni International BV	100.00		Eq.
Eni TNS Ltd	Aberdeen (United Kingdom)	United Kingdom	GBP	1,000	Eni UK Ltd	100.00	100.00	F.C.
Eni Tunisia BV	Amsterdam (Netherlands)	Tunisia	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Turkmenistan Ltd	Hamilton (Bermuda)	Turkmenistan	USD	20,000	Burren En.(Berm)Ltd	100.00	100.00	F.C.
Eni UHL Ltd	London (United Kingdom)	United Kingdom	GBP	1	Eni ULT Ltd	100.00	100.00	F.C.
Eni UK Holding Plc	London (United Kingdom)	United Kingdom	GBP	424,050,000	Eni Lasmo Plc Eni UK Ltd	99.99 (—)	100.00	F.C.
Eni UK Ltd	London (United Kingdom)	United Kingdom	GBP	250,000,000	Eni International BV	100.00	100.00	F.C.
Eni UKCS Ltd	London (United Kingdom)	United Kingdom	GBP	100	Eni UK Ltd	100.00	100.00	F.C.
Eni Ukraine Holdings BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni Ukraine Llc	Kiev (Ukraine)	Ukraine	UAH	42,004,757.64	Eni Ukraine Hold.BV Eni International BV	99.99 0.01	100.00	F.C.
Eni Ukraine Shallow Waters BV	Amsterdam (Netherlands)	Ukraine	EUR	20,000	Eni Ukraine Hold.BV	100.00		Eq.
Eni ULT Ltd	London (United Kingdom)	United Kingdom	GBP	93,215,492.25	Eni Lasmo Plc	100.00	100.00	F.C.
Eni ULX Ltd	London (United Kingdom)	United Kingdom	GBP	200,010,000	Eni ULT Ltd	100.00	100.00	F.C.
Eni US Operating Co Inc	Dover, Delaware (USA)	USA	USD	1,000	Eni Petroleum Co Inc	100.00	100.00	F.C.
Eni USA Gas Marketing Llc	Dover, Delaware (USA)	USA	USD	10,000	Eni Marketing Inc	100.00	100.00	F.C.
Eni USA Inc	Dover, Delaware (USA)	USA	USD	1,000	Eni Oil & Gas Inc	100.00	100.00	F.C.
Eni Venezuela BV	Amsterdam (Netherlands)	Venezuela	EUR	20,000	Eni Venezuela E&P Holding	100.00	100.00	F.C.
Eni Venezuela E&P Holding SA	Bruxelles (Belgium)	Belgium	USD	254,057,680	Eni International BV Eni Oil Holdings BV	99.99 (—)	100.00	F.C.
Eni Ventures Plc (in liquidation)	London (United Kingdom)	United Kingdom	GBP	278,050,000	Eni International BV Eni Oil Holdings BV	99.99 (—)		Co.
Eni Vietnam BV	Amsterdam (Netherlands)	Vietnam	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Eni West Timor Ltd	London (United Kingdom)	Indonesia	GBP	1	Eni Indonesia Ltd	100.00	100.00	F.C.
Eni Yemen Ltd	London (United Kingdom)	United Kingdom	GBP	1,000	Burren Energy Plc	100.00		Eq.
EniProgetti Egypt Ltd	Cairo (Egypt)	Egypt	EGP	50,000	EniProgetti SpA Eni SpA	99.00 1.00		Eq.
Eurl Eni Algérie	Algiers (Algeria)	Algeria	DZD	1,000,000	Eni Algeria Ltd Sàrl	100.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
First Calgary Petroleums LP	Wilmington (USA)	Algeria	USD	1	Eni Canada Hold. Ltd FCP Partner Co ULC	99.99 0.01	100.00	F.C.
First Calgary Petroleums Partner Co ULC	Calgary (Canada)	Canada	CAD	10	Eni Canada Hold. Ltd	100.00	100.00	F.C.
Ieoc Exploration BV	Amsterdam (Netherlands)	Egypt	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Ieoc Production BV	Amsterdam (Netherlands)	Egypt	EUR	20,000	Eni International BV	100.00	100.00	F.C.
Lasmo Sanga Sanga Ltd	Hamilton (Bermuda)	Indonesia	USD	12,000	Eni Lasmo Plc	100.00	100.00	F.C.
Liverpool Bay Ltd	London (United Kingdom)	United Kingdom	USD	1	Eni ULX Ltd	100.00		Eq.
Nigerian Agip CPFA Ltd	Lagos (Nigeria)	Nigeria	NGN	1,262,500	NAOC Ltd Agip En Nat Res.Ltd Nigerian Agip E. Ltd	98.02 0.99 0.99		Co.
Nigerian Agip Exploration Ltd	Abuja (Nigeria)	Nigeria	NGN	5,000,000	Eni International BV Eni Oil Holdings BV	99.99 0.01	100.00	F.C.
Nigerian Agip Oil Co Ltd	Abuja (Nigeria)	Nigeria	NGN	1,800,000	Eni International BV Eni Oil Holdings BV	99.89 0.11	100.00	F.C.
OOO 'Eni Energhia'	Moscow (Russia)	Russia	RUB	2,000,000	Eni Energy Russia BV Eni Oil Holdings BV	99.90 0.10	100.00	F.C.
Zetah Congo Ltd	Nassau (Bahamas)	Republic of the Congo	USD	300	Eni Congo SA Burren En.Congo Ltd	66.67 33.33		Co.
Zetah Kouilou Ltd	Nassau (Bahamas)	Republic of the Congo	USD	2,000	Eni Congo SA Burren En.Congo Ltd Third parties	54.50 37.00 8.50		Co.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Gas & Power

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni gas e luce SpA	San Donato Milanese (MI)	Italy	EUR	750,000,000	Eni SpA	100.00	100.00	F.C.
Eni Gas Transport Services Srl	San Donato Milanese (MI)	Italy	EUR	120,000	Eni SpA	100.00		Co.
Eni Trading & Shipping SpA	Rome	Italy	EUR	60,036,650	Eni SpA	100.00	100.00	F.C.
EniPower Mantova SpA	San Donato Milanese (MI)	Italy	EUR	144,000,000	EniPower SpA Third parties	86.50 13.50	86.50	F.C.
EniPower SpA	San Donato Milanese (MI)	Italy	EUR	944,947,849	Eni SpA	100.00	100.00	F.C.
LNG Shipping SpA	San Donato Milanese (MI)	Italy	EUR	240,900,000	Eni SpA	100.00	100.00	F.C.
Trans Tunisian Pipeline Co SpA	San Donato Milanese (MI)	Tunisia	EUR	1,098,000	Eni SpA	100.00	100.00	F.C.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Adriaplin Podjetje za distribucijo zemeljskega plina doo Ljubljana	Ljubljana (Slovenia)	Slovenia	EUR	12,956,935	Eni gas e luce SpA Third parties	51.00 49.00	51.00	F.C.
Eni G&P Trading BV	Amsterdam (Netherlands)	Turkey	EUR	70,000	Eni International BV	100.00	100.00	F.C.
Eni Gas & Power France SA	Levallois Perret (France)	France	EUR	29,937,600	Eni gas e luce SpA Third parties	99.87 0.13	99.87	F.C.
Eni Trading & Shipping Inc	Dover, Delaware (USA)	USA	USD	36,000,000	ETS SpA	100.00	100.00	F.C.
Eni Transporte y Suministro México, S. de RL de CV	Mexico City (Mexico)	Mexico	MXN	3,000	Eni International BV Eni Oil Holdings BV	99,90 0,10		Eq.
Gas Supply Company Thessaloniki - Thessalia SA	Thessaloniki (Greece)	Greece	EUR	13,761,788	Eni gas e luce SpA	100,00	100.00	F.C.
Société de Service du Gazoduc Transtunisien SA - Sergaz SA	Tunisi (Tunisia)	Tunisia	TND	99,000	Eni International BV Third parties	66.67 33.33	66.67	F.C.
Société pour la Construction du Gazoduc Transtunisien SA - Scogat SA	Tunisi (Tunisia)	Tunisia	TND	200,000	Eni International BV Eni SpA LNG Shipping SpA Trans Tunis.P.Co SpA	99.85 0.05 0.05 0.05	100.00	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Refining & Marketing and Chemical

Refining & Marketing

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Ecofuel SpA	San Donato Milanese (MI)	Italy	EUR	52,000,000	Eni SpA	100.00	100.00	F.C.
Eni Fuel SpA	Rome	Italy	EUR	58,944,310	Eni SpA	100.00	100.00	F.C.
Raffineria di Gela SpA	Gela (CL)	Italy	EUR	15,000,000	Eni SpA	100.00	100.00	F.C.
SeaPad SpA	Genova	Italy	EUR	12,400,000	Ecofuel SpA Third parties	80.00 20.00		Eq.
Servizi Fondo Bombole Metano SpA	Rome	Italy	EUR	13,580,000.20	Eni SpA	100.00		Co.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Eni Abu Dhabi Refining & Trading BV	Amsterdam (Netherlands)	Netherlands	EUR	20,000	Eni International BV	100.00		Eq.
Eni Austria GmbH	Wien (Austria)	Austria	EUR	78,500,000	Eni International BV Eni Deutsch.GmbH	75.00 25.00	100.00	F.C.
Eni Benelux BV	Rotterdam (Netherlands)	Netherlands	EUR	1,934,040	Eni International BV	100.00	100.00	F.C.
Eni Deutschland GmbH	Munich (Germany)	Germany	EUR	90,000,000	Eni International BV Eni Oil Holdings BV	89.00 11.00	100.00	F.C.
Eni Ecuador SA	Quito (Ecuador)	Ecuador	USD	103,142.08	Eni International BV Esain SA	99.93 0.07	100.00	F.C.
Eni France Sàrl	Lyon (France)	France	EUR	56,800,000	Eni International BV	100.00	100.00	F.C.
Eni Iberia SLU	Alcobendas (Spain)	Spain	EUR	17,299,100	Eni International BV	100.00	100.00	F.C.
Eni Lubricants Trading (Shanghai) Co Ltd	Shanghai (China)	China	EUR	5,000,000	Eni International BV	100.00	100.00	F.C.
Eni Marketing Austria GmbH	Wien (Austria)	Austria	EUR	19,621,665.23	Eni Mineralölh.GmbH Eni International BV	99.99 (—)	100.00	F.C.
Eni Mineralölhandel GmbH	Wien (Austria)	Austria	EUR	34,156,232.06	Eni Austria GmbH	100.00	100.00	F.C.
Eni Schmiertechnik GmbH	Wurzburg (Germany)	Germany	EUR	2,000,000	Eni Deutsch.GmbH	100.00	100.00	F.C.
Eni Suisse SA	Lausanne (Switzerland)	Switzerland	CHF	102,500,000	Eni International BV	100.00	100.00	F.C.
Eni USA R&M Co Inc	Wilmington (USA)	USA	USD	11,000,000	Eni International BV	100.00	100.00	F.C.
Esacontrol SA	Quito (Ecuador)	Ecuador	USD	60,000	Eni Ecuador SA Third parties	87.00 13.00		Eq.
Esain SA	Quito (Ecuador)	Ecuador	USD	30,000	Eni Ecuador SA Tecnoesa SA	99.99 (—)	100.00	F.C.
Oléoduc du Rhône SA	Valais (Switzerland)	Switzerland	CHF	7,000,000	Eni International BV	100.00		Eq.
OOO "Eni-Nefto"	Moscow (Russia)	Russia	RUB	1,010,000	Eni International BV Eni Oil Holdings BV	99.01 0.99		Eq.
Tecnoesa SA	Quito (Ecuador)	Ecuador	USD	36,000	Eni Ecuador SA Esain SA	99.99 (—)		Eq.

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Chemical

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method[(*)]
Versalis SpA	San Donato Milanese (MI)	Italy	EUR	1,364,790,000	Eni SpA	100.00	100.00	F.C.
In Italy								
Consorzio Industriale Gas Naturale (in liquidation)	San Donato Milanese (MI)	Italy	EUR	124,000	Versalis SpA Raff. di Gela SpA Eni SpA Syndial SpA Raff. Milazzo ScpA	53.55 18.74 15.37 0.76 11.58		Eq.
Outside Italy								
Dunastyr Polisztirolgyártó Zártkörûen Mûködõ Részvénytársaság	Budapest (Hungary)	Hungary	HUF	8,092,160,000	Versalis SpA Versalis Deutsc.GmbH Versalis Int.SA	96.34 1.83 1.83	100.00	F.C.
Versalis Americas Inc	Dover, Delaware (USA)	USA	USD	100,000	Versalis Int.SA	100.00	100.00	F.C.
Versalis Congo Sarlu	Pointe-Noire (Republic of the Congo)	Republic of the Congo	CDF	1,000,000	Versalis Int.SA	100.00		Eq.
Versalis Deutschland GmbH	Eschborn (Germany)	Germany	EUR	100,000	Versalis SpA	100.00	100.00	F.C.
Versalis France SAS	Mardyck (France)	France	EUR	126,115,582.90	Versalis SpA	100.00	100.00	F.C.
Versalis International SA	Bruxelles (Belgium)	Belgium	EUR	15,449,173.88	Versalis SpA Versalis Deutsc.GmbH Dunastyr Zrt Versalis France	59.00 23.71 14.43 2.86	100.00	F.C.
Versalis Kimya Ticaret Limited Sirketi	Istanbul (Turkey)	Turkey	TRY	20,000	Versalis Int.SA	100.00		Eq.
Versalis Pacific (India) Private Ltd	Mumbai (India)	India	INR	238,700	Versalis Sing. P. Ltd Third parties	99.99 (..)		Eq.
Versalis Pacific Trading (Shanghai) Co Ltd	Shanghai (China)	China	CNY	1,000,000	Versalis SpA	100.00	100.00	F.C.
Versalis Singapore Pte Ltd	Singapore (Singapore)	Singapore	SGD	80,000	Versalis SpA	100.00	100.00	F.C.
Versalis UK Ltd	London (United Kingdom)	United Kingdom	GBP	4,004,042	Versalis SpA	100.00	100.00	F.C.

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Corporate and other activities

Corporate and financial companies

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
In Italy								
Agenzia Giornalistica Italia SpA	Rome	Italy	EUR	2,000,000	Eni SpA	100.00	100.00	F.C.
Eni Adfin SpA (in liquidation)	Rome	Italy	EUR	85,537,498.80	Eni SpA Third parties	99.67 0.33	99.67	F.C.
Eni Corporate University SpA	San Donato Milanese (MI)	Italy	EUR	3,360,000	Eni SpA	100.00	100.00	F.C.
EniServizi SpA	San Donato Milanese (MI)	Italy	EUR	13,427,419.08	Eni SpA	100.00	100.00	F.C.
Serfactoring SpA	San Donato Milanese (MI)	Italy	EUR	5,160,000	Eni SpA Third parties	49.00 51.00	49.00	F.C.
Servizi Aerei SpA	San Donato Milanese (MI)	Italy	EUR	79,817,238	Eni SpA	100.00	100.00	F.C.
Outside Italy								
Banque Eni SA	Bruxelles (Belgium)	Belgium	EUR	50,000,000	Eni International BV Eni Oil Holdings BV	99.90 0.10	100.00	F.C.
Eni Finance International SA	Bruxelles (Belgium)	Belgium	USD	2,474,225,632	Eni International BV Eni SpA	66.39 33.61	100.00	F.C.
Eni Finance USA Inc	Dover, Delaware (USA)	USA	USD	15,000,000	Eni Petroleum Co Inc	100.00	100.00	F.C.
Eni Insurance Designated Activity Company	Dublin (Ireland)	Ireland	EUR	500,000,000	Eni SpA	100.00	100.00	F.C.
Eni International BV	Amsterdam (Netherlands)	Netherlands	EUR	641,683,425	Eni SpA	100.00	100.00	F.C.
Eni International Resources Ltd	London (United Kingdom)	United Kingdom	GBP	50,000	Eni SpA Eni UK Ltd	99.99 (—)	100.00	F.C.
Eni Next Llc	Houston (USA)	USA	USD	100	Eni Petroleum Co Inc	100.00	100.00	F.C.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Other Activities

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method[(*)]
In Italy								
Anic Partecipazioni SpA (in liquidation)	Gela (CL)	Italy	EUR	23,519,847.16	Syndial SpA Third parties	99.97 0.03		Eq.
Eni Energia Srl	San Donato Milanese (MI)	Italy	EUR	10,000	Eni SpA	100.00		Co.
Eni New Energy SpA	San Donato Milanese (MI)	Italy	EUR	9,296,000	Eni SpA	100.00	100.00	F.C.
Industria Siciliana Acido Fosforico - ISAF - SpA (in liquidation)	Gela (CL)	Italy	EUR	1,300,000	Syndial SpA Third parties	52.00 48.00		Eq.
Ing. Luigi Conti Vecchi SpA	Assemini (CA)	Italy	EUR	5,518,620.64	Syndial SpA	100.00	100.00	F.C.
Syndial Servizi Ambientali SpA	San Donato Milanese (MI)	Italy	EUR	425,647,621.42	Eni SpA Third parties	99.99 (—)	100.00	F.C.
Outside Italy								
Arm Wind Llp	Astana (Kazakhstan)	Kazakhstan	KZT	2,133,967,100	Windirect BV	100.00	90.00	F.C.
Eni New Energy Egypt SAE	Cairo (Egypt)	Egypt	EGP	250,000	Eni International BV Ieoc Exploration BV Ieoc Production BV	99.98 0.01 0.01		Eq.
Oleodotto del Reno SA	Coira (Switzerland)	Switzerland	CHF	1,550,000	Syndial SpA	100.00		Eq.
Windirect BV	Amsterdam (Netherlands)	Netherlands	EUR	10,000	Eni International BV Third parties	90.00 10.00	90.00	F.C.

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Joint arrangements and associates

Exploration & Production

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Mozambique Rovuma Venture SpA (†)	San Donato Milanese (MI)	Mozambique	EUR	20,000,000	Eni SpA Third parties	35.71 64.29	35.71	J.O.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Agiba Petroleum Co (†)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	50.00 50.00		Co.
Angola LNG Ltd	Hamilton (Bermuda)	Angola	USD	10,082,000,000	Eni Angola Prod.BV Third parties	13.60 86.40		Eq.
Ashrafi Island Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	25.00 75.00		Co.
Barentsmorneftegaz Sàrl(†)	Luxembourg (Luxembourg)	Russia	USD	20,000	Eni Energy Russia BV Third parties	33.33 66.67		Eq.
Cabo Delgado Gas Development Limitada(†)	Maputo (Mozambique)	Mozambique	MZN	2,500,000	Eni Mozam.LNG H. BV Third parties	50.00 50.00		Co.
Cardón IV SA(†)	Caracas (Venezuela)	Venezuela	VES	172.1	Eni Venezuela BV Third parties	50.00 50.00		Eq.
Compañia Agua Plana SA	Caracas (Venezuela)	Venezuela	VES	0.001	Eni Venezuela BV Third parties	26.00 74.00		Co.
Coral FLNG SA	Maputo (Mozambique)	Mozambique	MZN	100,000,000	Eni Mozam.LNG H. BV Third parties	25.00 75.00		Eq.
Coral South FLNG DMCC	Dubai (United Arab Emirates)	United Arab Emirates	AED	500,000	Eni Mozam.LNG H. BV Third parties	25.00 75.00		Eq.
East Delta Gas Co (in liquidation)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	37.50 62.50		Co.
East Kanayis Petroleum Co(†)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	50.00 50.00		Co.
East Obaiyed Petroleum Company(†)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc SpA Third parties	50.00 50.00		Co.
El Temsah Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	25.00 75.00		Co.
El-Fayrouz Petroleum Co(†) (in liquidation)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Exploration BV Third parties	50.00 50.00		Co.
Fedynskmorneftegaz Sàrl(†)	Luxembourg (Luxembourg)	Russia	USD	20,000	Eni Energy Russia BV Third parties	33.33 66.67		Eq.
Isatay Operating Company Llp(†)	Astana (Kazakhstan)	Kazakhstan	KZT	400,000	Eni Isatay BV Third parties	50.00 50.00		Co.
Karachaganak Petroleum Operating BV	Amsterdam (Netherlands)	Kazakhstan	EUR	20,000	Agip Karachag.BV Third parties	29.25 70.75		Co.
Karachaganak Project Development Ltd (KPD)	Reading, Berkshire (United Kingdom)	United Kingdom	GBP	100	Agip Karachag.BV Third parties	38.00 62.00		Eq.
Khaleej Petroleum Co Wll	Safat (Kuwait)	Kuwait	KWD	250,000	Eni Middle E. Ltd Third parties	49.00 51.00		Eq.
Liberty National Development Co Llc	Wilmington (USA)	USA	USD	0(a)	Eni Oil & Gas Inc Third parties	32.50 67.50		Eq.

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(†) Jointly controlled entity.
(a) Shares without nominal value.

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Mediterranean Gas Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	25.00 75.00		Co.
Mellitah Oil & Gas BV(†)	Amsterdam (Netherlands)	Libya	EUR	20,000	Eni North Africa BV Third parties	50.00 50.00		Co.
Nile Delta Oil Co Nidoco	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	37.50 62.50		Co.
Norpipe Terminal Holdco Ltd	London (United Kingdom)	Norway	GBP	55.69	Eni SpA Third parties	14.20 85.80		Eq.
North Bardawil Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Exploration BV Third parties	30.00 70.00		Co.
North El Burg Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc SpA Third parties	25.00 75.00		Co.
Petrobel Belayim Petroleum Co(†)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	50.00 50.00		Co.
PetroBicentenario SA(†)	Caracas (Venezuela)	Venezuela	VES	3,790	Eni Lasmo Plc Third parties	40.00 60.00		Eq.
PetroJunín SA(†)	Caracas (Venezuela)	Venezuela	VES	24,021	Eni Lasmo Plc Third parties	40.00 60.00		Eq.
PetroSucre SA	Caracas (Venezuela)	Venezuela	VES	2,203	Eni Venezuela BV Third parties	26.00 74.00		Eq.
Pharaonic Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	25.00 75.00		Co.
Point Resources FPSO Holding AS	Sandnes (Norway)	Norway	NOK	60,000	Vår Energi AS	100.00		
Point Resources FPSO AS	Sandnes (Norway)	Norway	NOK	150,100,000	PR FPSO Holding AS	100.00		
PR Jotun DA	Sandnes (Norway)	Norway	NOK	0(a)	PR FPSO AS PR FPSO Holding AS	95.00 5.00		
Port Said Petroleum Co(†)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	50.00 50.00		Co.
Raml Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	22.50 77.50		Co.
Ras Qattara Petroleum Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	37.50 62.50		Co.
Rovuma Basin LNG Land Limitada(†)	Maputo (Mozambique)	Mozambique	MZN	140,000	Mozamb. Rov. V. SpA Third parties	33.33 66.67		Co.
Shorouk Petroleum Company	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	25.00 75.00		Co.
Société Centrale Electrique du Congo SA	Pointe-Noire (Republic of the Congo)	Republic of the Congo	XAF	44,732,000,000	Eni Congo SA Third parties	20.00 80.00		Eq.
Société Italo Tunisienne d'Exploitation Pétrolière SA(†)	Tunisi (Tunisia)	Tunisia	TND	5,000,000	Eni Tunisia BV Third parties	50.00 50.00		Eq.
Sodeps - Société de Developpement et d'Exploitation du Permis du Sud SA(†)	Tunisi (Tunisia)	Tunisia	TND	100,000	Eni Tunisia BV Third parties	50.00 50.00		Co.
Tapco Petrol Boru Hatti Sanayi ve Ticaret AS(†) (in liquidation)	Istanbul (Turkey)	Turkey	TRY	9,850,000	Eni International BV Third parties	50.00 50.00		Co.
Tecninco Engineering Contractors Llp(†)	Aksai (Kazakhstan)	Kazakhstan	KZT	29,478,455	EniProgetti SpA Third parties	49.00 51.00		Eq.
Thekah Petroleum Co (in liquidation)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Exploration BV Third parties	25.00 75.00		Co.
United Gas Derivatives Co	Cairo (Egypt)	Egypt	USD	153,000,000	Eni International BV Third parties	33.33 66.67		Eq.
VIC CBM Ltd(†)	London (United Kingdom)	Indonesia	USD	1,315,912	Eni Lasmo Plc Third parties	50.00 50.00		Eq.
Virginia Indonesia Co CBM Ltd(†)	London (United Kingdom)	Indonesia	USD	631,640	Eni Lasmo Plc Third parties	50.00 50.00		Eq.
Vår Energi AS(†) (former Eni Norge AS)	Forus (Norway)	Norway	NOK	399,425,000	Eni International BV Third parties	69.60 30.40		Eq.
West Ashrafi Petroleum Co(†) (in liquidation)	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Exploration BV Third parties	50.00 50.00		Co.

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(†) Jointly controlled entity.
(a) Shares without nominal value.

Gas & Power

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Mariconsult SpA(†)	Milan	Italy	EUR	120,000	Eni SpA Third parties	50.00 50.00		Eq.
Società EniPower Ferrara Srl(†)	San Donato Milanese (MI)	Italy	EUR	140,000,000	EniPower SpA Third parties	51.00 49.00	51.00	J.O.
Transmed SpA(†)	Milan	Italy	EUR	240,000	Eni SpA Third parties	50.00 50.00		Eq.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Angola LNG Supply Services Llc	Wilmington (USA)	USA	USD	19,278,782	Eni USA Gas M. Llc Third parties	13.60 86.40		Eq.
Blue Stream Pipeline Co BV(†)	Amsterdam (Netherlands)	Russia	USD	22,000	Eni International BV Third parties	50.00 50.00	50.00	J.O.
Gas Distribution Company of Thessaloniki - Thessaly SA(†)	Ampelokipi-Menemeni (Greece)	Greece	EUR	247,127,605	Eni gas e luce SpA Third parties	49.00 51.00		Eq.
GreenStream BV(†)	Amsterdam (Netherlands)	Libya	EUR	200,000,000	Eni North Africa BV Third parties	50.00 50.00	50.00	J.O.
Premium Multiservices SA	Tunisi (Tunisia)	Tunisia	TND	200,000	Sergaz SA Third parties	49.99 50.01		Eq.
SAMCO Sagl	Lugano (Switzerland)	Switzerland	CHF	20,000	Transmed.Pip.Co Ltd Eni International BV Third parties	90.00 5.00 5.00		Eq.
Transmediterranean Pipeline Co Ltd(†)	St. Helier (Jersey)	Jersey	USD	10,310,000	Eni SpA Third parties	50.00 50.00	50.00	J.O.
Unión Fenosa Gas SA(†)	Madrid (Spain)	Spain	EUR	32,772,000	Eni SpA Third parties	50.00 50.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(†) Jointly controlled entity.

Refining & Marketing and Chemical

Refining & Marketing

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Arezzo Gas SpA (†)	Arezzo	Italy	EUR	394,000	Eni Fuel SpA Third parties	50.00 50.00		Eq.
CePIM Centro Padano Interscambio Merci SpA	Fontevivo (PR)	Italy	EUR	6,642,928.32	Ecofuel SpA Third parties	44.78 55.22		Eq.
Consorzio Operatori GPL di Napoli	Napoli	Italy	EUR	102,000	Eni Fuel SpA Third parties	25.00 75.00		Co.
Costiero Gas Livorno SpA(†)	Livorno	Italy	EUR	26,000,000	Eni Fuel SpA Third parties	65.00 35.00	65.00	J.O.
Disma SpA	Segrate (MI)	Italy	EUR	2,600,000	Eni Fuel SpA Third parties	25.00 75.00		Eq.
Livorno LNG Terminal SpA	Livorno	Italy	EUR	200,000	Costiero Gas Liv. SpA Third parties	50.00 50.00		Eq.
Petroven Srl(†)	Genova	Italy	EUR	156,000	Ecofuel SpA Third parties	68.00 32.00	68.00	J.O.
Porto Petroli di Genova SpA	Genova	Italy	EUR	2,068,000	Ecofuel SpA Third parties	40.50 59.50		Eq.
Raffineria di Milazzo ScpA(†)	Milazzo (ME)	Italy	EUR	171,143,000	Eni SpA Third parties	50.00 50.00	50.00	J.O.
Seram SpA	Fiumicino (RM)	Italy	EUR	852,000	Eni SpA Third parties	25.00 75.00		Co.
Sigea Sistema Integrato Genova Arquata SpA	Genova	Italy	EUR	3,326,900	Ecofuel SpA Third parties	35.00 65.00		Eq.
Società Oleodotti Meridionali - SOM SpA(†)	San Donato Milanese (MI)	Italy	EUR	3,085,000	Eni SpA Third parties	70.00 30.00	70.00	J.O.
Termica Milazzo Srl(†)	Milazzo (ME)	Italy	EUR	100,000	Raff. Milazzo ScpA	100.00	50.00	J.O.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(†) Jointly controlled entity.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method[*]
AET - Raffineriebeteiligungs gesellschaft mbH[†]	Schwedt (Germany)	Germany	EUR	27,000	Eni Deutsch.GmbH Third parties	33.33 66.67		Eq.
Bayernoil Raffineriegesellschaft mbH[†]	Vohburg (Germany)	Germany	EUR	10,226,000	Eni Deutsch.GmbH Third parties	20.00 80.00	20.00	J.O.
City Carburoil SA[†]	Rivera (Switzerland)	Switzerland	CHF	6,000,000	Eni Suisse SA Third parties	49.91 50.09		Eq.
Egyptian International Gas Technology Co	Cairo (Egypt)	Egypt	EGP	100,000,000	Eni International BV Third parties	40.00 60.00		Co.
ENEOS Italsing Pte Ltd	Singapore (Singapore)	Singapore	SGD	12,000,000	Eni International BV Third parties	22.50 77.50		Eq.
FSH Flughafen Schwechat Hydranten-Gesellschaft OG	Wien (Austria)	Austria	EUR	7,798,020.99	Eni Market.A.GmbH Eni Mineralölh.GmbH Eni Austria GmbH Third parties	14.56 14.56 14.56 56.32		Co.
Fuelling Aviation Services GIE	Tremblay en France (France)	France	EUR	1	Eni France Sàrl Third parties	25.00 75.00		Co.
Mediterranée Bitumes SA	Tunisi (Tunisia)	Tunisia	TND	1,000,000	Eni International BV Third parties	34.00 66.00		Eq.
Routex BV	Amsterdam (Netherlands)	Netherlands	EUR	67,500	Eni International BV Third parties	20.00 80.00		Eq.
Saraco SA	Meyrin (Switzerland)	Switzerland	CHF	420,000	Eni Suisse SA Third parties	20.00 80.00		Co.
Supermetanol CA[†]	Jose Puerto La Cruz (Venezuela)	Venezuela	VES	120,867	Ecofuel SpA Supermetanol CA Third parties	34.51[a] 30.07 35.42	50.00	J.O.
TBG Tanklager Betriebsgesellschaft GmbH[†]	Salzburg (Austria)	Austria	EUR	43,603.70	Eni Market.A.GmbH Third parties	50.00 50.00		Eq.
Weat Electronic Datenservice GmbH	Düsseldorf (Germany)	Germany	EUR	409,034	Eni Deutsch.GmbH Third parties	20.00 80.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

(†) Jointly controlled entity.

(a) Controlling interest: Ecofuel SpA 50.00; Third parties 50.00

Chemical

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
In Italy								
Brindisi Servizi Generali Scarl	Brindisi	Italy	EUR	1,549,060	Versalis SpA Syndial SpA EniPower SpA Third parties	49.00 20.20 8.90 21.90		Eq.
IFM Ferrara ScpA	Ferrara	Italy	EUR	5,270,466	Versalis SpA Syndial SpA S.E.F. Srl Third parties	19.74 11.58 10.70 57.98		Eq.
Matrica SpA(†)	Porto Torres (SS)	Italy	EUR	37,500,000	Versalis SpA Third parties	50.00 50.00		Eq.
Newco Tech SpA(†) (in liquidation)	Novara	Italy	EUR	179,000	Versalis SpA Genomatica Inc	80.00 20.00		Eq.
Novamont SpA	Novara	Italy	EUR	13,333,500	Versalis SpA Third parties	25.00 75.00		Eq.
Priolo Servizi ScpA	Melilli (SR)	Italy	EUR	28,100,000	Versalis SpA Syndial SpA Third parties	33.11 4.61 62.28		Eq.
Ravenna Servizi Industriali ScpA	Ravenna	Italy	EUR	5,597,400	Versalis SpA EniPower SpA Ecofuel SpA Third parties	42.13 30.37 1.85 25.65		Eq.
Servizi Porto Marghera Scarl	Porto Marghera (VE)	Italy	EUR	8,695,718	Versalis SpA Syndial SpA Third parties	48.44 38.39 13.17		Eq.
Outside Italy								
Lotte Versalis Elastomers Co Ltd(†)	Yeosu (South Korea)	South Korea	KRW	301,800,000,000	Versalis SpA Third parties	50.00 50.00		Eq.
Versalis Zeal Ltd(†)	Takoradi (Ghana)	Ghana	GHS	5,650,000	Versalis Intern. SA Third parties	80.00 20.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(†) Jointly controlled entity.

Corporate and other activities

Corporate and financial companies

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Outside Italy								
Commonwealth Fusion Systems Llc	Wilmington (USA)	USA	USD	148,291,710.38	Eni Next Llc Third parties	35.72 66.28		P.N.

Other activities

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	% Equity ratio	Consolidation or valutation method(*)
Filatura Tessile Nazionale Italiana - FILTENI SpA (in liquidation)	Ferrandina (MT)	Italy	EUR	4,644,000	Syndial SpA Third parties	59.56(a) 40.44		Co.
Ottana Sviluppo ScpA (in liquidation)	Nuoro	Italy	EUR	516,000	Syndial SpA Third parties	30.00 70.00		Eq.
Saipem SpA(#) (†)	San Donato Milanese (MI)	Italy	EUR	2,191,384,693	Eni SpA Saipem SpA Third parties	30.54(b) 1.46 68.00		Eq.
Outside Italy								
Grid Edge (Private) Ltd(†)	Saddar Town-Karachi (Pakistan)	Pakistan	PKR	1,200,000	Eni International BV Third parties	40.00 60.00		Eq.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(#) Company with shares quoted in the regulated market of Italy or of other EU countries
(†) Jointly controlled entity.

(a) Controlling interest:	Syndial SpA Third parties	48.00 52.00
(b) Controlling interest:	Eni SpA Third parties	30.99 69.01

Other significant investments

Exploration & Production

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	Consolidation or valutation method[(*)]
Consorzio Universitario in Ingegneria per la Qualità e l'Innovazione	Pisa	Italy	EUR	135,000	Eni SpA Third parties	25.00 75.00	F.V.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	Consolidation or valutation method[(*)]
Administradora del Golfo de Paria Este SA	Caracas (Venezuela)	Venezuela	VES	0.001	Eni Venezuela BV Third parties	19.50 80.50	F.V.
Brass LNG Ltd	Lagos (Nigeria)	Nigeria	USD	1,000,000	Eni Int. NA NV Sàrl Third parties	20.48 79.52	F.V.
Darwin LNG Pty Ltd	West Perth (Australia)	Australia	AUD	530.060.381,89	Eni G&P LNG Aus. BV Third parties	10.99 89.01	F.V.
New Liberty Residential Co Llc	West Trenton (USA)	USA	USD	0[(a)]	Eni Oil & Gas Inc Third parties	17.50 82.50	F.V.
Nigeria LNG Ltd	Port Harcourt (Nigeria)	Nigeria	USD	1,138,207,000	Eni Int. NA NV Sàrl Third parties	10.40 89.60	F.V.
North Caspian Operating Company NV	Amsterdam (Netherlands)	Kazakhstan	EUR	128,520	Agip Caspian Sea BV Third parties	16.81 83.19	F.V.
OPCO - Sociedade Operacional Angola LNG SA	Luanda (Angola)	Angola	AOA	7,400,000	Eni Angola Prod.BV Third parties	13.60 86.40	F.V.
Petrolera Güiria SA	Caracas (Venezuela)	Venezuela	VES	10	Eni Venezuela BV Third parties	19.50 80.50	F.V.
SOMG - Sociedade de Operações e Manutenção de Gasodutos SA	Luanda (Angola)	Angola	AOA	7,400,000	Eni Angola Prod.BV Third parties	13.60 86.40	F.V.
Torsina Oil Co	Cairo (Egypt)	Egypt	EGP	20,000	Ieoc Production BV Third parties	12.50 87.50	F.V.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(a) Shares without nominal value.

Gas & Power

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	Consolidation or valutation method(*)
Norsea Gas GmbH	Emden (Germany)	Germany	EUR	1,533,875.64	Eni International BV Third parties	13.04 86.96	F.V.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value

Refining & Marketing and Chemical

Refining & Marketing

In Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	Consolidation or valutation method[*]
Consorzio Nazionale per la Gestione Raccolta e Trattamento degli Oli Minerali Usati	Rome	Italy	EUR	36,149	Eni SpA Third parties	12.43 87.57	F.V.
Società Italiana Oleodotti di Gaeta SpA[(1)]	Rome	Italy	ITL	360,000,000	Eni SpA Third parties	72.48 27.52	F.V.

Outside Italy

Company name	Registered office	Country of operation	Currency	Share Capital	Shareholders	% Ownership	Consolidation or valutation method[*]
BFS Berlin Fuelling Services GbR	Hamburg (Germany)	Germany	EUR	89.199	Eni Deutsch.GmbH Third parties	12.50 87.50	F.V.
Compania de Economia Mixta 'Austrogas'	Cuenca (Ecuador)	Ecuador	USD	3,028,749	Eni Ecuador SA Third parties	13.31 86.69	F.V.
Dépôt Pétrolier de Fos SA	Fos-Sur-Mer (France)	France	EUR	3,954,196.40	Eni France Sàrl Third parties	16.81 83.19	F.V.
Dépôt Pétrolier de la Côte d'Azur SAS	Nanterre (France)	France	EUR	207,500	Eni France Sàrl Third parties	18.00 82.00	F.V.
Joint Inspection Group Ltd	London (United Kingdom)	United Kingdom	GBP	0[(a)]	Eni SpA Third parties	12.50 87.50	F.V.
Saudi European Petrochemical Company 'IBN ZAHR'	Al Jubail (Saudi Arabia)	Saudi Arabia	SAR	1,200,000,000	Ecofuel SpA Third parties	10.00 90.00	F.V.
S.I.P.G. Société Immobilier Pétrolier de Gestion Snc	Tremblay-En-France (France)	France	EUR	40,000	Eni France Sàrl Third parties	12.50 87.50	F.V.
Sistema Integrado de Gestion de Aceites Usados	Madrid (Spain)	Spain	EUR	175,713	Eni Iberia SLU Third parties	15.44 84.56	F.V.
Tanklager - Gesellschaft Tegel (TGT) GbR	Hamburg (Germany)	Germany	EUR	4.953	Eni Deutsch.GmbH Third parties	12.50 87.50	F.V.
TAR - Tankanlage Ruemlang AG	Ruemlang (Switzerland)	Switzerland	CHF	3,259,500	Eni Suisse SA Third parties	16.27 83.73	F.V.
Tema Lube Oil Co Ltd	Accra (Ghana)	Ghana	GHS	258,309	Eni International BV Third parties	12.00 88.00	F.V.

(*) F.C. = full consolidation, J.O. = joint operation, Eq. = equity-accounted, Co. = valued at cost, F.V. = valued at fair value
(a) Shares without nominal value.
(1) Company under extraordinary administration procedure pursuant to law no. 95 of april 3, 1979. The liquidation was concluded on april 28, 2015. The cancellation has been filed and is pending the authorization by the Ministry of Economic Development.

Information on Eni's consolidated subsidiaries with significant non-controlling interest

In 2018 and 2017, Eni did not own any consolidated subsidiaries with a significant non-controlling interest.

Total shareholders' equity pertaining to minority interests as of December 31, 2018, amounted to €57 million (€49 million at December 31, 2017).

Changes in the ownership interest without loss of control

In 2018 and 2017, Eni did not report any changes in ownership interest without loss or acquisition of control.

Principal joint ventures, joint operations and associates as of December 31, 2018

Company name	Registered office	Country of operation	Business segment	% ownership interest	% voting rights
Joint venture					
Gas Distribution Company of Thessaloniki - Thessaly SA	Ampelokipi-Menemeni (Greece)	Greece	Gas & Power	49.00	49.00
Saipem SpA	San Donato Milanese (MI) (Italy)	Italy	Other Activities	30.54	30.99
Unión Fenosa Gas SA	Madrid (Spain)	Spain	Gas & Power	50.00	50.00
Vår Energi AS	Forus (Norway)	Norway	Exploration & Production	69.60	69.60
Joint Operation					
GreenStream BV	Amsterdam (Netherlands)	Lybia	Gas & Power	50.00	50.00
Mozambique Rovuma Venture SpA	San Donato Milanese (MI) (Italy)	Mozambique	Exploration & Production	35.71	35.71
Raffineria di Milazzo ScpA	Milazzo (ME) (Italy)	Italy	Refining & Marketing	50.00	50.00
Associates					
Angola LNG Ltd	Hamilton (Bermuda)	Angola	Exploration & Production	13.60	13.60
Coral FLNG SA	Maputo (Mozambique)	Mozambique	Exploration & Production	25.00	25.00

The main line items of profit and loss and balance sheet related to the principal joint ventures, represented by the amounts included in the reports accounted under IFRS of each company, are provided in the table below:

	2018							
(€ million)	**Vår Energi AS**	**Saipem SpA**	**Unión Fenosa Gas SA**	**Gas Distribution Company of Thessaloniki -Thessaly SA**	**Cardón IV SA**	**Lotte Versalis Elastomers Co Ltd**	**PetroJunín SA**	**Other joint ventures**
Current assets	1,366	6,211	664	32	191	56	368	130
- *of which cash and cash equivalent*	*883*	*1,674*	*107*	*13*	*40*	*8*		*38*
Non-current assets	11,407	5,466	832	302	2,433	502	253	334
Total assets	**12,773**	**11,677**	**1,496**	**334**	**2,624**	**558**	**621**	**464**
Current liabilities	608	4,430	260	52	232	111	470	307
- *current financial liabilities*		*305*	*22*			*78*		*165*
Non-current liabilities	7,139	3,211	581	2	2,196	297	34	126
- *non-current financial liabilities*	*366*	*2,646*	*510*		*1,410*	*289*		*14*
Total liabilities	**7,747**	**7,641**	**841**	**54**	**2,428**	**408**	**504**	**433**
Net equity	**5,026**	**4,036**	**655**	**280**	**196**	**150**	**117**	**31**
Eni's ownership interest (%)	69.60	30.99	50.00	49.00	50.00	50.00	40.00	
Book value of the investment	**3,498**	**1,288**	**335**	**137**	**98**	**75**	**47**	**(2)**
Revenues and other operating income		8,530	1,521	53	610	22	112	731
Operating expense		(7,682)	(1,461)	(16)	(372)	(58)	(100)	(697)
Depreciation, amortization, impairments and reversal		(811)	(70)	(12)	(137)	(30)	(394)	(62)
Operating profit		**37**	**(10)**	**25**	**101**	**(66)**	**(382)**	**(28)**
Finance (expense) income		(165)	(31)		(208)	(12)	31	(5)
Income (expense) from investments		(88)	9					
Profit before income taxes		**(216)**	**(32)**	**25**	**(107)**	**(78)**	**(351)**	**(33)**
Income taxes		(194)	(1)	(8)	(35)		(19)	(10)
Net profit		**(410)**	**(33)**	**17**	**(142)**	**(78)**	**(370)**	**(43)**
Other comprehensive income		(46)	15		6		11	(4)
Total other comprehensive income		**(456)**	**(18)**	**17**	**(136)**	**(78)**	**(359)**	**(47)**
Net profit attributable to Eni		**(146)**	**(23)**	**8**	**(71)**	**(39)**	**(148)**	**(21)**
Dividends received from the joint venture				**8**				**11**

	2017						
(€ million)	**Saipem SpA**	**Unión Fenosa Gas SA**	**PetroJunín SA**	**Gas Distribution Company of Thessaloniki -Thessaly SA**	**Lotte Versalis Elastomeres Co**	**Cardón IV SA**	**Other joint ventures**
Current assets	6,743	610	365	86	43	816	275
- *of which cash and cash equivalent*	*1,751*	*32*		*15*	*30*	*42*	*64*
Non-current assets	5,847	877	628	289	547	2,756	916
Total assets	**12,590**	**1,487**	**993**	**375**	**590**	**3,572**	**1,191**
Current liabilities	4,487	234	434	94	70	644	985
- *current financial liabilities*	*189*	*40*			*38*		*640*
Non-current liabilities	3,504	580	34	2	292	2,928	124
- *non-current financial liabilities*	*2,929*	*506*			*288*	*1,912*	*79*
Total liabilities	**7,991**	**814**	**468**	**96**	**362**	**3,572**	**1,109**
Net equity	**4,599**	**673**	**525**	**279**	**228**		**82**
Eni's ownership interest (%)	31.00	50.00	40.00	49.00	50.00	50.00	
Book value of the investment	**1,413**	**350**	**210**	**137**	**114**		**28**
Revenues and other operating income	9,038	1,340	135	54		756	412
Operating expense	(8,172)	(1,308)	(66)	(14)	(4)	(608)	(433)
Depreciation, amortization and impairments	(740)	(89)	(29)	(15)		(357)	(113)
Operating profit	**126**	**(57)**	**40**	**25**	**(4)**	**(209)**	**(134)**
Finance (expense) income	(223)	(38)	47			(155)	(53)
Income (expense) from investments	(9)	3					(4)
Profit before income taxes	**(106)**	**(92)**	**87**	**25**	**(4)**	**(364)**	**(191)**
Income taxes	(201)	1	(22)	(7)		(4)	(11)
Net profit	**(307)**	**(91)**	**65**	**18**	**(4)**	**(368)**	**(202)**
Other comprehensive income	49	(41)	(68)		(6)	26	
Total other comprehensive income	**(258)**	**(132)**	**(3)**	**18**	**(10)**	**(394)**	**(202)**
Net profit attributable to Eni	**(101)**	**(63)**	**26**	**9**	**(2)**	**(184)**	**(56)**
Dividends received from the joint venture				**12**			**29**

The main line items of profit and loss and balance sheet related to the principal associates represented by the amounts included in the reports accounted under IFRS of each company are provided in the table below:

	2018		
(€ million)	**Angola LNG Ltd**	**Coral FLNG SA**	**Other associates**
Current assets	1,027	109	926
- *of which cash and cash equivalent*	*698*	*109*	*178*
Non-current assets	9,079	2,434	2,296
Total assets	**10,106**	**2,543**	**3,222**
Current liabilities	472	117	785
- *current financial liabilities*			*134*
Non-current liabilities	1,500	2,018	1,755
- *non-current financial liabilities*	*1,328*	*2,016*	*1,473*
Total liabilities	**1,972**	**2,135**	**2,540**
Net equity	**8,134**	**408**	**682**
Eni's ownership interest (%)	13.60	25.00	
Book value of the investment	**1,106**	**102**	**241**
Revenues and other operating income	1,919		1,053
Operating expense	(872)	(1)	(887)
Depreciation, amortization, impairments and reversal	1,647		(58)
Operating profit	**2,694**	**(1)**	**108**
Finance (expense) income	(97)	(11)	(1)
Income (expense) from investments			16
Profit before income taxes	**2,597**	**(12)**	**123**
Income taxes			(26)
Net profit	**2,597**	**(12)**	**97**
Other comprehensive income	337	16	17
Total other comprehensive income	**2,934**	**4**	**114**
Net profit attributable to Eni	**353**	**(3)**	**25**
Dividends received from the associate			**25**

(€ million)	2017 Angola LNG Ltd	2017 Coral FLNG SA	2017 Other associates
Current assets	662	36	338
- of which cash and cash equivalent	*370*	*19*	*89*
Non-current assets	7,048	1,261	528
Total assets	**7,710**	**1,297**	**866**
Current liabilities	203	155	220
- current financial liabilities			*42*
Non-current liabilities	1,610	926	124
- non-current financial liabilities	*1,418*	*926*	*71*
Total liabilities	**1,813**	**1,081**	**344**
Net equity	**5,897**	**216**	**522**
Eni's ownership interest (%)	13.60	25.00	
Book value of the investment	**802**	**54**	**205**
Revenues and other operating income	1,374		574
Operating expense	(563)		(454)
Depreciation, depletion, amortization and impairments	(399)		(40)
Operating profit	**412**		**80**
Finance (expense) income	(80)	4	3
Income (expense) from investments			(30)
Profit before income taxes	**332**	**4**	**53**
Income taxes			(19)
Net profit	**332**	**4**	**34**
Other comprehensive income	(817)	(13)	(39)
Total other comprehensive income	**(485)**	**(9)**	**(5)**
Net profit attributable to Eni	**45**	**1**	**8**
Dividends received from the associate			**13**

38 Public assistance — Italian Law no. 124/2017 and subsequent modifications

Under art. 1, paragraphs 125 and 126, of the Italian Law no. 124/2017 and subsequent modifications, the disclosures about the assistance received from Italian public authorities and entities, as well as the assistance granted by Eni SpA and by its fully consolidated subsidiaries to companies, persons and public and private entities, are provided below. The consolidated disclosures include: (i) assistance received from Italian public authorities/entities; and (ii) assistance granted by Eni SpA and its subsidiaries.[30]

The following disclosure requirements do not apply to: (i) incentives/subventions granted to all those entitled in accordance with a general assistance aid scheme; (ii) consideration in exchange for supplied goods/services, including sponsorships; (iii) reimbursements and indemnities paid to persons engaged in professional and orientation trainings; (iv) continuous training contributions to companies granted by inter-professional funds established in the legal form of association; (v) membership fees for the participation to industry trade and territorial associations, as well as to foundations or similar organizations, which perform activities linked with the company's business; (vi) costs incurred with reference to social projects linked to the investing activities of the company. The assistance to be disclosed is identified on a cash basis.

The disclosure includes assistance exceeding EUR 10,000, even though they are granted through several payments.

Under art. 3-quarter of the Italian Decree Law No. 135/2018, converted with amendments by Law 11 February 2019, n. 12, for the received assistance see the information included in the Italian State aid Register, prepared in accordance with the article 52 of the Italian Law 24 December 2012, No. 234.

30 The following disclosures do not include assistance granted by foreign subsidiaries to foreign beneficiaries.

The granted assistance provided herein is mainly referred to foundations, associations and other entities for reputational purposes, donations and support for charitable and solidarity initiatives:

Granted subject	Amount paid (€)
Fondazione Eni Enrico Mattei	4,403,686
Eni Foundation	3,389,902
Fondazione Teatro alla Scala	3,052,192
Fondazione Giorgio Cini	1,000,000
WEF – World Economic Forum	260,586
Comitato Sisma Centro Italia – Confindustria, CIGL, CISL e UIL – Fondo di solidarietà per le popolazioni Centro Italia	242,326
Council on Foreign Relations	83,358
Atlantic Council of the United States Inc	81,307
World Business Council for Sustainable Development	72,805
Associazione Pionieri e Veterani Eni	57,000
EITI – Extractive Industries Transparency Initiative	51,588
Bruegel	50,000
Parrocchia di S. Barbara a San Donato Milanese	40,000
Aspen Institute Italia	35,000
Italiadecide	35,000
Fondazione Camera Centro Italiano per la Fotografia	33,000
Istituto Giannina Gaslini	30,000
Center for Strategic & International Studies	29,687
Politecnico di Milano – Dipartimento di "Scienze e Tecnologie Energetiche e Nucleari"	26,000
Institute for Human Rights and Business (IHRB)	22,548
Associazione Civita	22,000
Foreign Policy Association – USA	21,985
The Metropolitan Museum of Arts	21,760
Associazione Amici della Luiss	20,000
Centro Studi Americani	20,000
Fondazione Human Foundation Giving and Innovating Onlus	20,000
Global Reporting Initiative	14,000
Lega Italiana Fibrosi Cistica Lazio Onlus	10,000

39 Significant non-recurring events and operations

In 2018, in 2017 and 2016, Eni did not report any non-recurring events and operations.

40 Positions or transactions deriving from atypical and/or unusual operations

In 2018, 2017 and 2016 no transactions deriving from atypical and/or unusual operations were reported.

41 Subsequent events

No significant events were reported after December 31, 2018.

Supplemental oil and gas information (unaudited)

The following information pursuant to "International Financial Reporting Standards" (IFRS) is presented in accordance with FASB Extractive Activities — Oil & Gas (Topic 932). Amounts related to minority interests are not significant.

Capitalized costs

Capitalized costs represent the total expenditures for proved and unproved mineral interests and related support equipment and facilities utilized in oil and gas exploration and production activities, together with related accumulated depreciation, depletion and amortization. Capitalized costs by geographical area consist of the following:

(€ million)

2018	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Proved property	16,569	6,236	14,140	17,474	40,607	11,240	12,711	15,347	1,967	136,291
Unproved property	18	332	456	56	2,311	3	1,530	861	193	5,760
Support equipment and facilities	369	21	1,516	208	1,281	108	38	52	12	3,605
Incomplete wells and other	653	103	1,554	1,504	2,307	1,382	562	595	127	8,787
Gross Capitalized Costs	**17,609**	**6,692**	**17,666**	**19,242**	**46,506**	**12,733**	**14,841**	**16,855**	**2,299**	**154,443**
Accumulated depreciation, depletion and amortization	(13,717)	(5,355)	(11,741)	(11,722)	(29,727)	(2,175)	(10,460)	(13,443)	(1,265)	(99,605)
Net Capitalized Costs consolidated subsidiaries[(a)]	**3,892**	**1,337**	**5,925**	**7,520**	**16,779**	**10,558**	**4,381**	**3,412**	**1,034**	**54,838**
Equity-accounted entities										
Proved property		9,102	58		1,481		2	1,912		12,555
Unproved property		1,045					11			1,056
Support equipment and facilities		25	6					7		38
Incomplete wells and other		364	10		10		19	224		627
Gross Capitalized Costs		10,536	74		1,491		32	2,143		14,276
Accumulated depreciation, depletion and amortization		(4,543)	(54)		(266)		(19)	(1,052)		(5,934)
Net Capitalized Costs equity-accounted entities[(a)(b)]		5,993	20		1,225		13	1,091		8,342
2017										
Consolidated subsidiaries										
Proved property	16,277	17,600	12,514	15,211	36,976	10,547	12,493	14,840	1,950	138,408
Unproved property	18	356	471	32	2,157	3	1,023	785	185	5,030
Support equipment and facilities	359	39	1,436	191	1,212	101	34	46	14	3,432
Incomplete wells and other	681	345	2,050	1,297	2,679	1,417	421	280	124	9,294
Gross Capitalized Costs	**17,335**	**18,340**	**16,471**	**16,731**	**43,024**	**12,068**	**13,971**	**15,951**	**2,273**	**156,164**
Accumulated depreciation, depletion and amortization	(13,504)	(12,014)	(10,640)	(10,413)	(25,920)	(1,690)	(10,386)	(12,534)	(1,188)	(98,289)
Net Capitalized Costs consolidated subsidiaries[(a)]	**3,831**	**6,326**	**5,831**	**6,318**	**17,104**	**10,378**	**3,585**	**3,417**	**1,085**	**57,875**
Equity-accounted entities										
Proved property			67		1,419		581	1,833		3,900
Unproved property		4					85			89
Support equipment and facilities			7					6		13
Incomplete wells and other		1	6		4		93	225		329
Gross Capitalized Costs		**5**	**80**		**1,423**		**759**	**2,064**		**4,331**
Accumulated depreciation, depletion and amortization			(61)		(475)		(611)	(785)		(1,932)
Net Capitalized Costs equity-accounted entities[(a)]		5	19		948		148	1,279		2,399

(a) The amounts include net capitalized financial charges totalling €831 million in 2018 and €969 million in 2017 for the consolidated subsidiaries and €180 million in 2018 and €78 million in 2017 for equity-accounted entities.

(b) Includes Vår Energi AS asset fair value.

Costs incurred

Costs incurred represent amounts both capitalized and expensed in connection with oil and gas producing activities. Costs incurred by geographical area consist of the following:

(€ million) **2018**	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub - Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Proved property acquisitions							382			382
Unproved property acquisitions							487			487
Exploration	26	106	43	102	66	3	182	215	7	750
Development[(a)]	382	557	445	2,216	1,379	92	589	340	36	6,036
Total costs incurred consolidated subsidiaries	**408**	**663**	**488**	**2,318**	**1,445**	**95**	**1,640**	**555**	**43**	**7,655**
Equity-accounted entities										
Proved property acquisitions		0								0
Unproved property acquisitions		0								0
Exploration			2				103			105
Development[(b)]		0	3					(16)		(13)
Total costs incurred equity-accounted entities		**0**	**5**				**103**	**(16)**		**92**

2017	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub - Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Proved property acquisitions					5					5
Unproved property acquisitions										
Exploration	31	242	77	110	65	3	76	106	5	715
Development[(a)]	251	364	785	3,041	1,939	246	714	292	14	7,646
Total costs incurred consolidated subsidiaries	**282**	**606**	**862**	**3,151**	**2,009**	**249**	**790**	**398**	**19**	**8,366**
Equity-accounted entities										
Proved property acquisitions										
Unproved property acquisitions										
Exploration		1					90			91
Development[(b)]			2		9		4	48		63
Total costs incurred equity-accounted entities		**1**	**2**		**9**		**94**	**48**		**154**

2016										
Consolidated subsidiaries										
Proved property acquisitions										
Unproved property acquisitions				2						2
Exploration	27	51	58	306	70		80	26	3	621
Development[(a)]	387	437	694	1,752	2,019	651	1,232	(5)	1	7,168
Total costs incurred consolidated subsidiaries	**414**	**488**	**752**	**2,060**	**2,089**	**651**	**1,312**	**21**	**4**	**7,791**
Equity-accounted entities										
Proved property acquisitions										
Unproved property acquisitions										
Exploration		1					13			14
Development[(b)]			1		28		12	95		136
Total costs incurred equity-accounted entities		**1**	**1**		**28**		**25**	**95**		**150**

(a) Includes the abandonment costs of the assets negative for €517 million in 2018, assets for €355 million in 2017, negative for €665 million in 2016.
(b) Includes the abandonment costs of the assets negative for €22 million in 2018, negative €23 million in 2017, negative for €15 million in 2016.

Results of operations from oil and gas producing activities

Results of operations from oil and gas producing activities represent only those revenues and expenses directly associated with such activities, including operating overheads. These amounts do not include any allocation of interest expenses or general corporate overheads and, therefore, are not necessarily indicative of the contributions to consolidated net earnings of Eni. Related income taxes are calculated by applying the local income tax rates to the pre-tax income from production activities. Eni is party to certain Production Sharing Agreements (PSAs), whereby a portion of Eni's share of oil and gas production is withheld and sold by its joint venture partners which are state owned entities, with proceeds being remitted to the state to meet Eni's PSA related tax liabilities. Revenue and income taxes include such taxes owed by Eni but paid by state-owned entities out of Eni's share of oil and gas production. Results of operations from oil and gas producing activities by geographical area consist of the following:

(€ million) **2018**	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub - Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Revenues:										
- sales to consolidated entities	2,120	2,740	1,277		4,701	1,140	1,902	934	4	14,818
- sales to third parties		494	3,741	3,207	830	769	493	50	190	9,774
Total revenues	**2,120**	**3,234**	**5,018**	**3,207**	**5,531**	**1,909**	**2,395**	**984**	**194**	**24,592**
Operations costs	(410)	(630)	(413)	(354)	(1,016)	(405)	(227)	(250)	(48)	(3,753)
- *of which production costs*	(402)	(488)	(363)	(343)	(974)	(269)	(220)	(234)	(48)	(3,341)
- *of which transportation costs*	(8)	(142)	(50)	(11)	(42)	(136)	(7)	(16)		(412)
Production taxes	(171)		(243)		(435)		(191)		(6)	(1,046)
Exploration expenses	(25)	(85)	(48)	(22)	(44)	(3)	(79)	(69)	(5)	(380)
D.D. & A. and Provision for abandonment[(a)]	(281)	(664)	(582)	(795)	(2,490)	(387)	(941)	(594)	(67)	(6,801)
Other income (expenses)	(442)	(193)	(101)	(239)	(1,126)	(67)	(135)	(54)		(2,357)
Pretax income from producing activities	**791**	**1,662**	**3,631**	**1,797**	**420**	**1,047**	**822**	**17**	**68**	**10,255**
Income taxes	(170)	(1,070)	(2,494)	(542)	(264)	(308)	(678)	7	(26)	(5,545)
Results of operations from E&P activities of consolidated subsidiaries	**621**	**592**	**1,137**	**1,255**	**156**	**739**	**144**	**24**	**42**	**4,710**
Equity-accounted entities										
Revenues:										
- sales to consolidated entities										
- sales to third parties			15		257		6	420		698
Total revenues			**15**		**257**		**6**	**420**		**698**
Operations costs			(8)		(62)		(2)	(38)		(110)
- *of which production costs*			(7)		(34)		(2)	(36)		(79)
- *of which transportation costs*			(1)		(28)			(2)		(31)
Production taxes			(3)		(26)			(114)		(143)
Exploration expenses		(6)					(235)			(241)
D.D. & A. and Provision for abandonment			(1)		224		(3)	(222)		(2)
Other income (expenses)		(1)	2		(27)		(25)	(122)		(173)
Pretax income from producing activities		**(7)**	**5**		**366**		**(259)**	**(76)**		**29**
Income taxes			(3)				(2)	(35)		(40)
Results of operations from E&P activities of equity-accounted entities		**(7)**	**2**		**366**		**(261)**	**(111)**		**(11)**

(a) Includes asset net impairment amounting to €726 million.

(€ million) 2017	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Revenues:										
- sales to consolidated entities	1,619	1,897	1,056		3,888	681	911	932	3	10,987
- sales to third parties		481	3,184	2,128	547	713	291	96	168	7,608
Total revenues	**1,619**	**2,378**	**4,240**	**2,128**	**4,435**	**1,394**	**1,202**	**1,028**	**171**	**18,595**
Operations costs	(337)	(687)	(504)	(314)	(986)	(396)	(206)	(312)	(48)	(3,790)
- *of which production costs*	(332)	(523)	(455)	(303)	(952)	(271)	(202)	(258)	(48)	(3,344)
- *of which transportation costs*	(5)	(164)	(49)	(11)	(34)	(125)	(4)	(54)		(446)
Production taxes	(130)		(200)		(331)		(11)		(5)	(677)
Exploration expenses	(26)	(122)	(22)	(191)	(60)		(61)	(39)	(4)	(525)
D.D. & A. and Provision for abandonment[(a)]	(465)	(838)	(679)	(767)	(2,063)	(289)	(765)	(577)	(59)	(6,502)
Other income (expenses)	1,563	(141)	(162)	690	(716)	(221)	(84)	(342)	2	589
Pretax income from producing activities	**2,224**	**590**	**2,673**	**1,546**	**279**	**488**	**75**	**(242)**	**57**	**7,690**
Income taxes	(299)	(216)	(1,978)	(214)	(38)	(223)	(67)	(38)	(23)	(3,096)
Results of operations from E&P activities of consolidated subsidiaries	**1,925**	**374**	**695**	**1,332**	**241**	**265**	**8**	**(280)**	**34**	**4,594**
Equity-accounted entities										
Revenues:										
- sales to consolidated entities										
- sales to third parties			14		129		22	517		682
Total revenues			**14**		**129**		**22**	**517**		**682**
Operations costs			(8)		(37)		(9)	(40)		(94)
- *of which production costs*			(6)		(19)		(9)	(39)		(73)
- *of which transportation costs*			(2)		(18)			(1)		(21)
Production taxes			(2)		(8)			(146)		(156)
Exploration expenses		(1)					(13)			(14)
D.D. & A. and Provision for abandonment			(1)		(54)		(13)	(271)		(339)
Other income (expenses)		(2)	(2)		26		3	(199)		(174)
Pretax income from producing activities		**(3)**	**1**		**56**		**(10)**	**(139)**		**(95)**
Income taxes			(1)				(4)	(20)		(25)
Results of operations from E&P activities of equity-accounted entities		**(3)**			**56**		**(14)**	**(159)**		**(120)**

(a) Includes asset net reversal amounting to €158 million

(€ million) 2016	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Revenues:										
- sales to consolidated entities	1,217	1,673	932	9	3,178	252	1,027	833	4	9,125
- sales to third parties		432	2,841	1,471	485	606	114	102	165	6,216
Total revenues	**1,217**	**2,105**	**3,773**	**1,480**	**3,663**	**858**	**1,141**	**935**	**169**	**15,341**
Operations costs	(311)	(599)	(451)	(356)	(968)	(269)	(215)	(325)	(49)	(3,543)
- *of which production costs*	(307)	(436)	(404)	(343)	(929)	(177)	(212)	(262)	(49)	(3,119)
- *of which transportation costs*	(4)	(163)	(47)	(13)	(39)	(92)	(3)	(63)		(424)
Production taxes	(96)		(176)		(282)		(17)		(5)	(576)
Exploration expenses	(35)	(40)	(45)	(42)	(142)		(39)	(28)	(3)	(374)
D.D. & A. and Provision for abandonment[(a)]	(923)	(943)	(675)	(691)	(1,093)	(129)	(952)	(480)	(67)	(5,953)
Other income (expenses)	(342)	(232)	(201)	(265)	(917)	(57)	(130)	(120)	(8)	(2,272)
Pretax income from producing activities	**(490)**	**291**	**2,225**	**126**	**261**	**403**	**(212)**	**(18)**	**37**	**2,623**
Income taxes	159	(1)	(1,618)	(89)	97	(139)	32	(9)	(9)	(1,577)
Results of operations from E&P activities of consolidated subsidiaries	**(331)**	**290**	**607**	**37**	**358**	**264**	**(180)**	**(27)**	**28**	**1,046**
Equity-accounted entities										
Revenues:										
- sales to consolidated entities										
- sales to third parties			15				36	493		544
Total revenues			**15**				**36**	**493**		**544**
Operations costs			(9)				(10)	(54)		(73)
- *of which production costs*			(7)				(10)	(51)		(68)
- *of which transportation costs*			(2)					(3)		(5)
Production taxes			(3)					(121)		(124)
Exploration expenses							(13)			(13)
D.D. & A. and Provision for abandonment			(1)		(26)		(32)	(240)		(299)
Other income (expenses)		(3)	(1)		(26)		(16)	(25)		(71)
Pretax income from producing activities		**(3)**	**1**		**(52)**		**(35)**	**53**		**(36)**
Income taxes			(2)				(6)	(162)		(170)
Results of operations from E&P activities of equity-accounted entities		**(3)**	**(1)**		**(52)**		**(41)**	**(109)**		**(206)**

(a) Includes asset net reversal amounting to €700 million

Oil and natural gas reserves

Eni's criteria concerning evaluation and classification of proved developed and undeveloped reserves follow Regulation S-X 4-10 of the U.S. Securities and Exchange Commission and have been disclosed in accordance with FASB Extractive Activities - Oil & Gas (Topic 932).

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. 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 un-weighted 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.

In 2018, the average price for the marker Brent crude oil was $71 per barrel.

Net proved reserves exclude interests and royalties owned by others. Proved reserves are classified as either developed or undeveloped. Developed oil and gas reserves are reserves that can be expected to be recovered 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. 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.

Eni has its proved reserves audited on a rotational basis by independent oil engineering companies.[4] The description of qualifications of the person primarily responsible of the reserves audit is included in the third party audit report[5].

In the preparation of their reports, independent evaluators rely, without independent verification, upon data furnished by Eni with respect to property interest, production, current costs of operation and development, sale agreements, prices and other factual information and data that were accepted as represented by the independent evaluators. These data, equally used by Eni in its internal process, include logs, directional surveys, core and PVT (Pressure Volume Temperature) analysis, maps, oil/gas/water production/injection data of wells, reservoir studies and technical analysis relevant to field performance, long-term development plans, future capital and operating costs. In order to calculate the economic value of Eni equity reserves, actual prices applicable to hydrocarbon sales, price adjustments required by applicable contractual arrangements, and other pertinent information are provided.

In 2018, Ryder Scott Company, DeGolyer and MacNaughton and Societé Generale de Surveillance (SGS)[5] provided an independent evaluation of about 26% of Eni's total proved reserves as of December 31, 2018[6], confirming, as in previous years, the reasonableness of Eni's internal evaluations.

In the three years period from 2016 to 2018, 95% of Eni's total proved reserves were subject to independent evaluation. As of December 31, 2018, the principal property not subjected to independent evaluation in the last three years was M'Boundi (Congo).

Eni operates under production sharing agreements in several of the foreign jurisdictions where it has oil and gas exploration and production activities. Reserves of oil and natural gas to which Eni is entitled under PSA arrangements are shown in accordance with Eni's economic interest in the volumes of oil and natural gas estimated to be recoverable in future years. Such reserves include estimated quantities allocated to Eni for recovery of costs, income taxes owed by Eni but settled by its joint venture partners (which are state-owned entities) out of Eni's share of production and Eni's net equity share after cost recovery. Proved oil and gas reserves associated with PSAs represented 61%, 60% and 59% of total proved reserves as of December 31, 2018, 2017 and 2016, respectively, on an oil-equivalent basis. Similar effects as PSAs apply to service contracts; proved reserves associated with such contracts represented 3%, 4% and 5% of total proved reserves on an oil-equivalent basis as of December 31, 2018, 2017 and 2016, respectively.

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4 From 1991 to 2002 DeGolyer and McNaughton, from 2003 also Ryder Scott. In 2018, Societé Generale de Surveillance (SGS).

5 See "Item 19 – Exhibits".

6 Including reserves of equity-accounted entities.

Oil and gas reserves quantities include: (i) oil and natural gas quantities in excess of cost recovery which the company has an obligation to purchase under certain PSAs with governments or authorities, whereby the company serves as producer of reserves. Reserves volumes associated with oil and gas deriving from such obligation represent 4%, 1.6% and 1.8% of total proved reserves as of December 31, 2018, 2017 and 2016, respectively, on an oil equivalent basis; (ii) volumes of natural gas used for own consumption; (iii) the quantities of hydrocarbons related to the Angola LNG plant.

Numerous uncertainties are inherent in estimating quantities of proved reserves, in projecting future productions and development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and evaluation. The results of drilling, testing and production after the date of the estimate may require substantial upward or downward revisions. In addition, changes in oil and natural gas prices have an effect on the quantities of Eni's proved reserves since estimates of reserves are based on prices and costs relevant to the date when such estimates are made. Consequently, the evaluation of reserves could also significantly differ from actual oil and natural gas volumes that will be produced.

The following table presents yearly changes in estimated proved reserves, developed and undeveloped, of crude oil (including condensate and natural gas liquids) and natural gas as of December 31, 2018, 2017 and 2016.

(million barrels)

2018	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub - Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Reserves at December 31, 2017	215	360	476	280	764	766	232	162	7	3,262
of which: developed	169	219	306	203	546	547	81	144	5	2,220
undeveloped	46	141	170	77	218	219	151	18	2	1,042
Purchase of Minerals in Place							319			319
Revisions of Previous Estimates	15	6	73	21	30	(27)	(54)	23	(1)	86
Improved Recovery				7			6			13
Extensions and Discoveries					13		1	86		100
Production	(22)	(40)	(56)	(28)	(89)	(35)	(28)	(19)	(1)	(318)
Sales of Minerals in Place		(278)		(1)						(279)
Reserves at December 31, 2018	**208**	**48**	**493**	**279**	**718**	**704**	**476**	**252**	**5**	**3,183**
Equity-accounted entities										
Reserves at December 31, 2017			12		12			136		160
of which: developed			12		6			25		43
undeveloped					6			111		117
Purchase of Minerals in Place		297								297
Revisions of Previous Estimates					1			(96)		(95)
Improved Recovery										
Extensions and Discoveries										
Production			(1)		(1)			(3)		(5)
Sales of Minerals in Place										
Reserves at December 31, 2018		**297**	**11**		**12**			**37**		**357**
Reserves at December 31, 2018	**208**	**345**	**504**	**279**	**730**	**704**	**476**	**289**	**5**	**3,540**
Developed	**156**	**198**	**328**	**153**	**559**	**587**	**252**	**175**	**5**	**2,413**
consolidated subsidiaries	156	44	317	153	551	587	252	143	5	2,208
equity-accounted entities		154	11		8			32		205
Undeveloped	**52**	**147**	**176**	**126**	**171**	**117**	**224**	**114**		**1,127**
consolidated subsidiaries	52	4	176	126	167	117	224	109		975
equity-accounted entities		143			4			5		152

2017	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Reserves at December 31, 2016	176	264	454	281	809	767	307	163	9	3,230
of which: developed	132	228	287	205	507	556	124	143	8	2,190
undeveloped	44	36	167	76	302	211	183	20	1	1,040
Purchase of Minerals in Place					2					2
Revisions of Previous Estimates	59	29	73	21	31	29	(69)	19	(1)	191
Improved Recovery		1	6	7			9			23
Extensions and Discoveries		103	1		18		4	3		129
Production	(20)	(37)	(58)	(26)	(90)	(30)	(19)	(23)	(1)	(304)
Sales of Minerals in Place				(3)	(6)					(9)
Reserves at December 31, 2017	**215**	**360**	**476**	**280**	**764**	**766**	**232**	**162**	**7**	**3,262**
Equity-accounted entities										
Reserves at December 31, 2016			13		15			140		168
of which: developed			13		8			22		43
undeveloped					7			118		125
Purchase of Minerals in Place										
Revisions of Previous Estimates					(2)			1		(1)
Improved Recovery										
Extensions and Discoveries										
Production			(1)		(1)			(5)		(7)
Sales of Minerals in Place										
Reserves at December 31, 2017			**12**		**12**			**136**		**160**
Reserves at December 31, 2017	**215**	**360**	**488**	**280**	**776**	**766**	**232**	**298**	**7**	**3,422**
Developed	**169**	**219**	**318**	**203**	**552**	**547**	**81**	**169**	**5**	**2,263**
consolidated subsidiaries	169	219	306	203	546	547	81	144	5	2,220
equity-accounted entities			12		6			25		43
Undeveloped	**46**	**141**	**170**	**77**	**224**	**219**	**151**	**129**	**2**	**1,159**
consolidated subsidiaries	46	141	170	77	218	219	151	18	2	1,042
equity-accounted entities					6			111		117

2016	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Reserves at December 31, 2015	228	305	494	327	787	771	262	189	9	3,372
of which: developed	171	237	312	230	511	355	126	149	9	2,100
undeveloped	57	68	182	97	276	416	136	40		1,272
Purchase of Minerals in Place										
Revisions of Previous Estimates	(35)	(4)	19	(26)	113	20	73	(1)	1	160
Improved Recovery		1	1							2
Extensions and Discoveries		2	1	8						11
Production	(17)	(40)	(61)	(28)	(91)	(24)	(28)	(25)	(1)	(315)
Sales of Minerals in Place										
Reserves at December 31, 2016	**176**	**264**	**454**	**281**	**809**	**767**	**307**	**163**	**9**	**3,230**
Equity-accounted entities										
Reserves at December 31, 2015			13		16			158		187
of which: developed			13		6			29		48
undeveloped					10			129		139
Purchase of Minerals in Place										
Revisions of Previous Estimates			1		(1)			(13)		(13)
Improved Recovery										
Extensions and Discoveries										
Production			(1)					(5)		(6)
Sales of Minerals in Place										
Reserves at December 31, 2016			**13**		**15**			**140**		**168**
Reserves at December 31, 2016	**176**	**264**	**467**	**281**	**824**	**767**	**307**	**303**	**9**	**3,398**
Developed	**132**	**228**	**300**	**205**	**515**	**556**	**124**	**165**	**8**	**2,233**
consolidated subsidiaries	132	228	287	205	507	556	124	143	8	2,190
equity-accounted entities			13		8			22		43
Undeveloped	**44**	**36**	**167**	**76**	**309**	**211**	**183**	**138**	**1**	**1,165**
consolidated subsidiaries	44	36	167	76	302	211	183	20	1	1,040
equity-accounted entities					7			118		125

(billion cubic feet)

Natural Gas[(a)]

2018	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Reserves at December 31, 2017	1,131	896	3,145	4,351	3,660	2,108	1,065	225	709	17,290
of which: developed	987	771	1,233	1,421	1,693	1,878	862	171	519	9,535
undeveloped	144	125	1,912	2,930	1,967	230	203	54	190	7,755
Purchase of Minerals in Place							69			69
Revisions of Previous Estimates	138	50	219	2,238	23	(22)	81	45	(16)	2,756
Improved Recovery										
Extensions and Discoveries	86				7		205	76		374
Production	(156)	(162)	(474)	(445)	(184)	(97)	(201)	(43)	(42)	(1,804)
Sales of Minerals in Place		(464)		(869)			(2)	(26)		(1,361)
Reserves at December 31, 2018	1,199	320	2,890	5,275	3,506	1,989	1,217	277	651	17,324
Equity-accounted entities										
Reserves at December 31, 2017			14		349			1,819		2,182
of which: developed			14		83			1,819		1,916
undeveloped					266					266
Purchase of Minerals in Place		360								360
Revisions of Previous Estimates			2		(6)			(22)		(26)
Improved Recovery										
Extensions and Discoveries										
Production			(2)		(33)			(81)		(116)
Sales of Minerals in Place										
Reserves at December 31, 2018		360	14		310			1,716		2,400
Reserves at December 31, 2018	**1,199**	**680**	**2,904**	**5,275**	**3,816**	**1,989**	**1,217**	**1,993**	**651**	**19,724**
Developed	**980**	**576**	**1,461**	**3,331**	**1,928**	**1,846**	**822**	**1,870**	**452**	**13,266**
consolidated subsidiaries	980	300	1,447	3,331	1,871	1,846	822	154	452	11,203
equity-accounted entities		276	14		57			1,716		2,063
Undeveloped	**219**	**104**	**1,443**	**1,944**	**1,888**	**143**	**395**	**123**	**199**	**6,458**
consolidated subsidiaries	219	20	1,443	1,944	1,635	143	395	123	199	6,121
equity-accounted entities		84			253					337

2017	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Reserves at December 31, 2016	977	878	3,738	5,520	2,767	2,485	1,003	353	741	18,462
of which: developed	845	801	1,732	799	1,651	2,239	280	338	559	9,244
undeveloped	132	77	2,006	4,721	1,116	246	723	15	182	9,218
Purchase of Minerals in Place					1					1
Revisions of Previous Estimates	315	163	66	969	134	(281)	188	(61)	6	1,499
Improved Recovery			(19)							(19)
Extensions and Discoveries		29		64	1,839			4		1,936
Production	(161)	(174)	(640)	(315)	(162)	(96)	(126)	(71)	(38)	(1,783)
Sales of Minerals in Place				(1,887)	(919)					(2,806)
Reserves at December 31, 2017	1,131	896	3,145	4,351	3,660	2,108	1,065	225	709	17,290
Equity-accounted entities										
Reserves at December 31, 2016			15		368		4	3,484		3,871
of which: developed			15		104		4	1,782		1,905
undeveloped					264			1,702		1,966
Purchase of Minerals in Place										
Revisions of Previous Estimates					13			(1,565)		(1,552)
Improved Recovery										
Extensions and Discoveries										
Production			(1)		(32)		(4)	(100)		(137)
Sales of Minerals in Place										
Reserves at December 31, 2017			14		349			1,819		2,182
Reserves at December 31, 2017	**1,131**	**896**	**3,159**	**4,351**	**4,009**	**2,108**	**1,065**	**2,044**	**709**	**19,472**
Developed	**987**	**771**	**1,247**	**1,421**	**1,776**	**1,878**	**862**	**1,990**	**519**	**11,451**
consolidated subsidiaries	987	771	1,233	1,421	1,693	1,878	862	171	519	9,535
equity-accounted entities			14		83			1,819		1,916
Undeveloped	**144**	**125**	**1,912**	**2,930**	**2,233**	**230**	**203**	**54**	**190**	**8,021**
consolidated subsidiaries	144	125	1,912	2,930	1,967	230	203	54	190	7,755
equity-accounted entities					266					266

2016	Italy	Rest of Europe	North Africa	Egypt	Sub - Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Reserves at December 31, 2015	1,304	1,044	3,851	947	2,714	2,354	878	439	771	14,302
of which: developed	1,051	919	1,744	822	1,390	1,830	185	373	585	8,899
undeveloped	253	125	2,107	125	1,324	524	693	66	186	5,403
Purchase of Minerals in Place										
Revisions of Previous Estimates	(155)	18	471	25	223	224	200	8	12	1,026
Improved Recovery										
Extensions and Discoveries				4,767			15			4,782
Production	(172)	(184)	(584)	(219)	(170)	(93)	(90)	(94)	(42)	(1,648)
Sales of Minerals in Place										
Reserves at December 31, 2016	977	878	3,738	5,520	2,767	2,485	1,003	353	741	18,462
Equity-accounted entities										
Reserves at December 31, 2015			13		387		12	3,581		3,993
of which: developed			13		85		9	1,295		1,402
undeveloped					302		3	2,286		2,591
Purchase of Minerals in Place										
Revisions of Previous Estimates			4		(8)		(1)	(4)		(9)
Improved Recovery										
Extensions and Discoveries										
Production			(2)		(11)		(7)	(93)		(113)
Sales of Minerals in Place										
Reserves at December 31, 2016			15		368		4	3,484		3,871
Reserves at December 31, 2016	**977**	**878**	**3,753**	**5,520**	**3,135**	**2,485**	**1,007**	**3,837**	**741**	**22,333**
Developed	**845**	**801**	**1,747**	**799**	**1,755**	**2,239**	**284**	**2,120**	**559**	**11,149**
consolidated subsidiaries	845	801	1,732	799	1,651	2,239	280	338	559	9,244
equity-accounted entities			15		104		4	1,782		1,905
Undeveloped	**132**	**77**	**2,006**	**4,721**	**1,380**	**246**	**723**	**1,717**	**182**	**11,184**
consolidated subsidiaries	132	77	2,006	4,721	1,116	246	723	15	182	9,218
equity-accounted entities					264			1,702		1,966

(a) Values lower than 1 BCF are not disclosed in this table.

Standardized measure of discounted future net cash flows

Estimated future cash inflows represent the revenues that would be received from production and are determined by applying the year-end average prices during the years ended.

Future price changes are considered only to the extent provided by contractual arrangements. Estimated future development and production costs are determined by estimating the expenditures to be incurred in developing and producing the proved reserves at the end of the year. Neither the effects of price and cost escalations nor expected future changes in technology and operating practices have been considered.

The standardized measure is calculated as the excess of future cash inflows from proved reserves less future costs of producing and developing the reserves, future income taxes and a yearly 10% discount factor.

Future production costs include the estimated expenditures related to the production of proved reserves plus any production taxes without consideration of future inflation. Future development costs include the estimated costs of drilling development wells and installation of production facilities, plus the net costs associated with dismantlement and abandonment of wells and facilities, under the assumption that year-end costs continue without considering future inflation. Future income taxes were calculated in accordance with the tax laws of the countries in which Eni operates.

The standardized measure of discounted future net cash flows, related to the preceding proved oil and gas reserves, is calculated in accordance with the requirements of FASB Extractive Activities — Oil & Gas (Topic 932). The standardized measure does not purport to reflect realizable values or fair market value of Eni’s proved reserves. An estimate of fair value would also take into account, among other things, hydrocarbon resources other than proved reserves, anticipated changes in future prices and costs and a discount factor representative of the risks inherent in the oil and gas exploration and production activity.

The standardized measure of discounted future net cash flows by geographical area consists of the following:

(€ million) **December 31, 2018**	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Future cash inflows	18,372	4,895	43,578	39,193	53,534	40,698	33,384	14,192	2,319	250,165
Future production costs	(5,659)	(1,438)	(6,653)	(12,193)	(16,417)	(8,276)	(9,492)	(6,038)	(511)	(66,677)
Future development and abandonment costs	(4,670)	(1,350)	(4,700)	(2,769)	(6,778)	(2,640)	(5,755)	(2,467)	(291)	(31,420)
Future net inflow before income tax	**8,043**	**2,107**	**32,225**	**24,231**	**30,339**	**29,782**	**18,137**	**5,687**	**1,517**	**152,068**
Future income tax	(1,671)	(798)	(17,514)	(7,829)	(11,566)	(6,524)	(11,980)	(1,791)	(289)	(59,962)
Future net cash flows	**6,372**	**1,309**	**14,711**	**16,402**	**18,773**	**23,258**	**6,157**	**3,896**	**1,228**	**92,106**
10% discount factor	(2,045)	(124)	(6,727)	(6,564)	(7,501)	(12,477)	(2,258)	(1,508)	(491)	(39,695)
Standardized measure of discounted future net cash flows	**4,327**	**1,185**	**7,984**	**9,838**	**11,272**	**10,781**	**3,899**	**2,388**	**737**	**52,411**
Equity-accounted entities										
Future cash inflows		18,608	347		2,675			8,292		29,922
Future production costs		(4,686)	(138)		(873)			(2,192)		(7,889)
Future development and abandonment costs		(3,633)	(3)		(75)			(191)		(3,902)
Future net inflow before income tax		**10,289**	**206**		**1,727**			**5,909**		**18,131**
Future income tax		(6,822)	(43)		(204)			(1,839)		(8,908)
Future net cash flows		**3,467**	**163**		**1,523**			**4,070**		**9,223**
10% discount factor		(1,104)	(76)		(793)			(2,009)		(3,982)
Standardized measure of discounted future net cash flows		**2,363**	**87**		**730**			**2,061**		**5,241**
Total consolidated subsidiaries and equity-accounted entities	**4,327**	**3,548**	**8,071**	**9,838**	**12,002**	**10,781**	**3,899**	**4,449**	**737**	**57,652**

December 31, 2017	**Italy**	**Rest of Europe**	**North Africa**	**Egypt**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**America**	**Australia and Oceania**	**Total**
Consolidated subsidiaries										
Future cash inflows	14,339	19,507	31,793	29,156	41,136	30,263	11,826	6,205	2,593	186,818
Future production costs	(5,091)	(5,711)	(6,677)	(6,153)	(14,790)	(6,992)	(3,653)	(2,351)	(590)	(52,008)
Future development and abandonment costs	(3,943)	(5,483)	(4,350)	(4,496)	(6,522)	(2,787)	(3,694)	(1,011)	(318)	(32,604)
Future net inflow before income tax	**5,305**	**8,313**	**20,766**	**18,507**	**19,824**	**20,484**	**4,479**	**2,843**	**1,685**	**102,206**
Future income tax	(859)	(4,490)	(10,836)	(5,709)	(6,418)	(3,970)	(757)	(699)	(303)	(34,041)
Future net cash flows	**4,446**	**3,823**	**9,930**	**12,798**	**13,406**	**16,514**	**3,722**	**2,144**	**1,382**	**68,165**
10% discount factor	(1,633)	(1,050)	(4,566)	(6,698)	(5,430)	(9,172)	(1,239)	(777)	(607)	(31,172)
Standardized measure of discounted future net cash flows	**2,813**	**2,773**	**5,364**	**6,100**	**7,976**	**7,342**	**2,483**	**1,367**	**775**	**36,993**
Equity-accounted entities										
Future cash inflows			245		2,062		11	10,797		13,115
Future production costs			(119)		(930)		(6)	(3,291)		(4,346)
Future development and abandonment costs			(1)		(66)			(535)		(602)
Future net inflow before income tax			**125**		**1,066**		**5**	**6,971**		**8,167**
Future income tax			(21)		(57)		(1)	(2,459)		(2,538)
Future net cash flows			**104**		**1,009**		**4**	**4,512**		**5,629**
10% discount factor			(50)		(471)			(2,475)		(2,996)
Standardized measure of discounted future net cash flows			**54**		**538**		**4**	**2,037**		**2,633**
Total consolidated subsidiaries and equity-accounted entities	**2,813**	**2,773**	**5,418**	**6,100**	**8,514**	**7,342**	**2,487**	**3,404**	**775**	**39,626**

December 31, 2016	Italy	Rest of Europe	North Africa	Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	America	Australia and Oceania	Total
Consolidated subsidiaries										
Future cash inflows	9,627	12,898	30,847	33,524	38,271	26,903	12,263	5,789	2,815	172,937
Future production costs	(4,136)	(5,240)	(7,481)	(7,927)	(13,913)	(9,247)	(3,498)	(2,935)	(658)	(55,035)
Future development and abandonment costs	(3,641)	(3,575)	(5,904)	(6,981)	(9,392)	(3,268)	(5,047)	(1,313)	(270)	(39,391)
Future net inflow before income tax	**1,850**	**4,083**	**17,462**	**18,616**	**14,966**	**14,388**	**3,718**	**1,541**	**1,887**	**78,511**
Future income tax	(237)	(1,308)	(9,253)	(5,941)	(4,525)	(2,596)	(953)	(298)	(341)	(25,452)
Future net cash flows	**1,613**	**2,775**	**8,209**	**12,675**	**10,441**	**11,792**	**2,765**	**1,243**	**1,546**	**53,059**
10% discount factor	(241)	(365)	(4,060)	(8,055)	(4,594)	(6,536)	(1,266)	(501)	(724)	(26,342)
Standardized measure of discounted future net cash flows	**1,372**	**2,410**	**4,149**	**4,620**	**5,847**	**5,256**	**1,499**	**742**	**822**	**26,717**
Equity-accounted entities										
Future cash inflows			259		2,429		33	16,430		19,151
Future production costs			(143)		(974)		(20)	(4,614)		(5,751)
Future development and abandonment costs			(1)		(64)			(1,186)		(1,251)
Future net inflow before income tax			**115**		**1,391**		**13**	**10,630**		**12,149**
Future income tax			(21)		(115)		(4)	(3,667)		(3,807)
Future net cash flows			**94**		**1,276**		**9**	**6,963**		**8,342**
10% discount factor			(46)		(734)			(4,441)		(5,221)
Standardized measure of discounted future net cash flows			**48**		**542**		**9**	**2,522**		**3,121**
Total consolidated subsidiaries and equity-accounted entities	**1,372**	**2,410**	**4,197**	**4,620**	**6,389**	**5,256**	**1,508**	**3,264**	**822**	**29,838**

Changes in standardized measure of discounted future net cash flows

Changes in standardized measure of discounted future net cash flows for the years ended December 31, 2018, 2017 and 2016, are as follows:
(€ million)

	Consolidated subsidiaries	Equity-accounted entities	Total
2018			
Standardized measure of discounted future net cash flows at December 31, 2017	**36,993**	**2,633**	**39,626**
Increase (Decrease):			
- sales, net of production costs	(19,793)	(445)	(20,238)
- net changes in sales and transfer prices, net of production costs	27,970	671	28,641
- extensions, discoveries and improved recovery, net of future production and development costs	1,649		1,649
- changes in estimated future development and abandonment costs	(2,525)	216	(2,309)
- development costs incurred during the period that reduced future development costs	6,468	14	6,482
- revisions of quantity estimates	10,487	(803)	9,684
- accretion of discount	5,670	384	6,054
- net change in income taxes	(16,566)	193	(16,373)
- purchase of reserves in-place	5,369	6,700	12,069
- sale of reserves in-place	(8,363)		(8,363)
- changes in production rates (timing) and other	5,052	(4,322)	730
Net increase (decrease)	**15,418**	**2,608**	**18,026**
Standardized measure of discounted future net cash flows at December 31, 2018	**52,411**	**5,241**	**57,652**
2017			
Standardized measure of discounted future net cash flows at December 31, 2016	**26,717**	**3,121**	**29,838**
Increase (Decrease):			
- sales, net of production costs	(14,125)	(432)	(14,557)
- net changes in sales and transfer prices, net of production costs	23,940	1,482	25,422
- extensions, discoveries and improved recovery, net of future production and development costs	1,697		1,697
- changes in estimated future development and abandonment costs	(2,817)	495	(2,322)
- development costs incurred during the period that reduced future development costs	7,203	45	7,248
- revisions of quantity estimates	5,269	(2,285)	2,984
- accretion of discount	3,864	438	4,302
- net change in income taxes	(6,498)	238	(6,260)
- purchase of reserves in-place	10		10
- sale of reserves in-place	(2,995)		(2,995)
- changes in production rates (timing) and other	(5,272)	(469)	(5,741)
Net increase (decrease)	**10,276**	**(488)**	**9,788**
Standardized measure of discounted future net cash flows at December 31, 2017	**36,993**	**2,633**	**39,626**
2016			
Standardized measure of discounted future net cash flows at December 31, 2015	**34,469**	**3,321**	**37,790**
Increase (Decrease):			
- sales, net of production costs	(11,222)	(347)	(11,569)
- net changes in sales and transfer prices, net of production costs	(24,727)	(1,586)	(26,313)
- extensions, discoveries and improved recovery, net of future production and development costs	4,563		4,563
- changes in estimated future development and abandonment costs	(2,357)	650	(1,707)
- development costs incurred during the period that reduced future development costs	7,578	151	7,729
- revisions of quantity estimates	2,840	(131)	2,709
- accretion of discount	5,705	514	6,219
- net change in income taxes	9,200	386	9,586
- purchase of reserves in-place			
- sale of reserves in-place			
- changes in production rates (timing) and other	668	163	831
Net increase (decrease)	**(7,752)**	**(200)**	**(7,952)**
Standardized measure of discounted future net cash flows at December 31, 2016	**26,717**	**3,121**	**29,838**

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Date: April 5, 2019

Eni SpA

/s/ MASSIMO MONDAZZI

Massimo Mondazzi
Title: Chief Financial Officer

EXHIBIT 1

By-laws of Eni SpA[1]
November 2014

Part I – Formation – Name – Registered Office and Duration of the Company

ARTICLE 1

1.1 Eni SpA, formed as a result of the transformation of Ente Nazionale Idrocarburi, a public agency, pursuant to Law No. 136 of February 10, 1953, is governed by these By-laws.

1.2 The first letter of the Company's name may be written in either upper or lower case.

ARTICLE 2

2.1 The Company's registered office is located in Rome, and it has two branch offices in San Donato Milanese (Milan).

2.2 The Company may establish and/or close offices, representative offices, affiliates and branch offices either in Italy or abroad, in the manner provided for by law.

ARTICLE 3

3.1 The duration of the Company shall expire on December 31, 2100. Its duration may be extended one or more times by resolution of the Shareholders' Meeting.

Part II – Corporate Purpose

ARTICLE 4

4.1 The corporate purpose is the direct and/or indirect exercise, through equity holdings in companies or other entities of activities in the field of hydrocarbons and natural gases, such as exploration and development of hydrocarbon fields, the construction and operation of pipelines for transporting the same, the processing, transformation, storage, use and sale of hydrocarbons and natural gases, in compliance with the terms of concessions provided for by law.

The corporate purpose also includes the direct and/or indirect exercise, through equity holdings in companies or other enterprises, of activities in the fields of chemicals, nuclear fuels, geothermal energy, other renewable energy sources and energy in general, in the design and construction of industrial plants, in the mining industry, in the metallurgy industry, in the textile machinery industry, in the water sector, including water diversion, potabilization, purification, distribution and reuse; in the environmental protection sector and the treatment and disposal of waste, as well as any other economic activity that is instrumental, ancillary or complementary to the afore mentioned activities.

The corporate purpose also comprises performing and managing the technical and financial coordination of subsidiaries and associated companies and providing financial assistance to them.

The Company may undertake any transactions necessary or useful for the achievement of the corporate purpose; by way of example, it may undertake transactions involving real estate or moveable assets, commercial and industrial transactions, financial and banking transactions of any sort, and any other act that is in any way connected with the corporate purpose with the exception of fundraising on a public basis and the performance of investment services as defined by Legislative Decree No. 58 of February 24, 1998.

The Company may, finally, acquire equity holdings and interests in other companies or enterprises with corporate purposes that are similar, related or complementary to its own or those of companies in which it has equity holdings, either in Italy or abroad, and it may provide secured and/or unsecured guarantees for its own and others' obligations, including, in particular, sureties.

Part III – Share capital – Shares – Bonds

ARTICLE 5

5.1 The Company's share capital is equal to euro 4,005,358,876.00 (four billion five million three hundred and fifty-eight thousand eight hundred and seventy-six), represented by 3,634,185,330 (three billion six hundred and thirty four million one hundred and eighty-five thousand three hundred and thirty) ordinary shares without indication of par value.

5.2 Shares may not be split and each share gives entitlement to one vote.

5.3 The status of shareholder in itself constitutes approval of these By-laws.

ARTICLE 6

6.1 Pursuant to Article 3 of Decree Law No. 332 of May 31, 1994, ratified with amendments by Law No. 474 of July 30, 1994, no shareholder may hold, in any capacity, more than 3% of the Company's share capital.

(1) The English text is a translation of the Italian official "By-laws of Eni SpA". For any conflict or discrepancies between the two texts the Italian text shall prevail.

The calculation of such maximum shareholding limit also takes account of the aggregate shareholding held by the controlling party, whether a natural or legal person or company; subsidiaries under direct or indirect control, as well as entities controlled by the same controlling party; linked entities and persons related to the second degree by blood or marriage, with the exception of legally separated spouses.
A relationship of control, including with reference to entities other than companies, exists in the cases envisaged by Article 2359, paragraphs 1 and 2 of the Italian Civil Code.
A link exists in the case set forth in Article 2359, paragraph 3, of the Italian Civil Code, as well as between entities that directly or indirectly, by way of subsidiaries other than those managing investment funds, participate, even with third parties, in agreements regarding the exercise of voting rights or the transfer of shares or other equity holdings in third-party companies or, in any event, in agreements as referred to in Article 122 of Legislative Decree No. 58 of February 24, 1998 regarding third-party companies if said agreements involve least 10% of voting share capital if they are listed companies or 20% if they are unlisted companies.
The calculation of the afore mentioned shareholding limit (3%) also takes account of shares held by any fiduciary and/or nominee.
Any voting rights and any other non-financial rights attached to shares held in excess of the maximum limit indicated above may not be exercised and the voting rights of each shareholder to whom such limit applies shall be reduced in proportion, unless otherwise jointly specified in advance by the parties involved. If the voting rights of shares exceeding this limit are exercised, any Shareholders' resolution adopted pursuant to such a vote may be challenged pursuant to Article 2377 of the Italian Civil Code if the required majority would not have been reached without the votes exceeding the afore mentioned maximum limit.
Shares for which voting rights may not be exercised shall nevertheless be included in the determination of the quorum at Shareholders' Meetings.

ARTICLE 7

7.1 When shares are fully paid up, and if the law so allows, they may be issued to bearer. Bearer shares may be converted into registered shares and vice-versa. Conversion operations shall be carried out at the shareholder's expense.

ARTICLE 8

8.1 If for whatever reason a share should belong to more than one person, the rights attaching to said share may be exercised by only one person or by a proxy acting for all co-holders.

ARTICLE 9

9.1 The Shareholders' Meeting may resolve to increase the Company share capital and set the terms, conditions and means thereof.

9.2 The Shareholders' Meeting may resolve to increase the Company share capital by issuing shares, including shares of different classes, to be granted for no consideration pursuant to Article 2349 of the Italian Civil Code.

ARTICLE 10

10.1 Payments in respect of shares may be called by the Board of Directors in one or more installments.

10.2 Shareholders who are late in payment shall be charged interest calculated at the official discount rate established by the Bank of Italy, without prejudice to the provisions of Article 2344 of the Italian Civil Code.

ARTICLE 11

11.1 The Company may issue bonds, including convertible bonds and warrants, in compliance with the provisions of law.

Part IV – Shareholders' Meetings

ARTICLE 12

12.1 Ordinary and extraordinary Shareholders' Meetings shall normally be held at the Company's registered office unless otherwise decided by the Board of Directors, provided however they are held in Italy.

12.2 The ordinary Shareholders' Meeting shall be called at least once a year, within 180 days of the end of the Company's financial year, to approve the financial statements, since the Company is required to draw up consolidated financial statements.

12.3 The directors shall call a Shareholders' Meeting without delay when shareholders representing at least one twentieth of the share capital so request. Shareholders' Meetings may not be called upon the request of the shareholders for matters upon which, according to law, the Shareholders' Meeting must resolve upon a proposal of the directors or on the basis of a project or report of the directors themselves. The shareholders who request a meeting to be convened shall prepare a report on the proposals relating to the matters to be discussed. The Board of Directors shall make the report available to the public, together with its own evaluations, if any, at the Company's registered office, on the Company's website and in any other manner established in Consob regulations at the time the notice calling the meeting is published.

12.4 The Board of Directors shall make a report on each of the items on the agenda available to the public as provided for in the previous paragraph by the deadlines for publication of the notice calling the Shareholders' Meeting for each of the items on the agenda.

ARTICLE 13

13.1 The Shareholders' Meeting shall be called by way of a notice published on the Company's website, as well as in accordance with the procedures specified in Consob regulations, by the statutory deadlines and in accordance with applicable law.

Shareholders who severally or jointly represent at least one fortieth of the Company's share capital may ask for items to be added to the agenda by submitting a request within ten days of publication of the notice calling the meeting, unless a different term is provided for by law, specifying the additional proposed items in their request or presenting proposed resolutions on items already on the agenda. Requests, together with the certificate attesting ownership of the shares, are submitted in writing, by mail or electronically in the manners provided for in the notice calling the meeting. These proposed resolutions may be presented individually at the Shareholders' Meeting by persons entitled to vote. Matters upon which, according to law, the Shareholders' Meeting must resolve upon a proposal of the Board of Directors or on the basis of a project or report of the directors other than the report on the items in the agenda, may not be added to the agenda. The Board of Directors shall give notice of the additions to the agenda or the proposed resolutions approved in the same manner prescribed for the publication of the notice calling the meeting at least fifteen days before the date set for the Shareholders' Meeting, unless a different term is required by law. The proposed resolutions on items already on the agenda are made available to the public as prescribed by Article 12.3 of these By-laws, simultaneous with publication of the announcement of their presentation. The requesting or proposing shareholders shall send, by the final deadline for the submission of requests for additions to the agenda or of proposed resolutions, a report to the Board of Directors, explaining the reasons for the addition or the proposed resolution. The Board of Directors shall make the report available to the public, together with its own evaluations, if any, at the same time as the publication of the notice of the additions to the agenda or of the presentation of proposed resolutions in the manner set out in Article 12.3 of these By-laws.

13.2 Entitlement to attend and cast a vote at the Shareholders' Meeting shall be certified by a statement submitted by an authorized intermediary on the basis of its accounting records to the Company on behalf of the person entitled to vote. The statement shall be issued by the intermediary on the basis of the balances on the accounts recorded at the end of the seventh trading day prior to the date of the Shareholders' Meeting. Credit or debit records entered on the accounts after this deadline shall not be considered for the purpose of determining entitlement to exercise voting rights at the Shareholders' Meeting. The statement issued by the authorized intermediary must reach the Company by the end of the third trading day prior to the date of the Shareholders' Meeting, or by any other deadline established by Consob regulations issued in agreement with the Bank of Italy. Shareholders shall nevertheless be entitled to attend the meeting and cast a vote if the statements are received by the Company after the deadlines indicated above, provided they are received before the start of proceedings of the given call. For the purposes of this Article, reference is made to the date of first call, provided that the dates of any subsequent calls are indicated in the notice calling the meeting; otherwise, the date of each call is deemed the reference date.

ARTICLE 14

14.1 Those persons who are entitled to vote may appoint a party to represent themselves at the Shareholders' Meeting by means of a written proxy or in electronic form in the manner set forth by current laws. Electronic notification of the proxy may be made through a special section of the Company's website as indicated in the notice calling the meeting. In order to simplify proxy voting by shareholders who are employees of the Company or of its subsidiaries and belong to shareholders associations that meet applicable statutory requirements, locations for communications and collecting proxies shall be made available to said associations in accordance with the terms and conditions agreed from time to time with the legal representatives of said associations.

14.2 The Chairman of the meeting shall verify the validity of proxies and, in general, entitlement to participate in the meeting.

14.3 The right to vote may also be exercised by correspondence in accordance with the applicable provisions of law and regulations. If envisaged in the notice calling the meeting, those persons entitled to vote may participate in the Shareholders' Meeting by means of telecommunication systems and exercise their right to vote by electronic means in accordance with the provisions of law, applicable regulations and the Shareholders' Meeting Rules.

14.4 The Shareholders' Meetings are governed by the Shareholders' Meeting Rules as approved with a resolution of the ordinary Shareholders' Meeting.

14.5 The Company may designate a person for each Shareholders' Meeting to whom the shareholders may confer a proxy with voting instructions on all or some of the items on the agenda, as provided for by law and regulations, by the end of the second trading day preceding the date set for the Shareholders' Meeting including for calls subsequent to the first. Such proxy shall not be valid for items in respect of which no voting instructions have been provided.

ARTICLE 15

15.1 The Shareholders' Meeting is chaired by the Chairman of the Board of Directors, or in the event of the Chairman's absence or impediment, by the Chief Executive Officer; in their absence, the Shareholders' Meeting shall elect its own Chairman.

15.2 The Chairman of the meeting is assisted by a Secretary, who need not be a shareholder, to be designated by the participants in the meeting, and may appoint one or more scrutineers.

ARTICLE 16

16.1 The ordinary Shareholders' Meeting decides on all matters for which it is legally responsible and authorizes the transfer of the business.

16.2 The ordinary and extraordinary Shareholders' Meetings, are normally held on single call; in such case the majorities required by law shall apply. The Board of Directors may, if deemed necessary, establish that both the ordinary and the extraordinary Shareholders' Meetings shall be held after more than one call; their resolutions in first, second or third call must be passed with the majorities required by law in each case.

16.3 The resolutions of the Shareholders' Meeting, approved in accordance with the law and these By-laws, shall be binding on all shareholders, including those dissenting or not present.

16.4 The minutes of ordinary meetings shall be signed by the Chairman and the Secretary.

16.5 The minutes of extraordinary meetings shall be drawn up by a notary public.

Part V – The Board of Directors

ARTICLE 17

17.1 The Company is governed by a Board of Directors consisting of no fewer than three and no more than nine members. The Shareholders' Meeting shall determine the number within these limits.

17.2 The directors shall be appointed for a period of up to three financial years; this term shall lapse on the date of the Shareholders' Meeting convened to approve the financial statements for their last year in office. They may be re-elected.

17.3 The Board of Directors shall be elected by the Shareholders' Meeting on the basis of slates presented by shareholders and by the Board of Directors. The candidates shall be listed on the slates in numerical order.

The slates shall be filed with the Company's registered office, including remotely in the manner indicated in the notice calling the meeting, by the twenty-fifth day before the date of the Shareholders' Meeting at first or single call convened to appoint the members of the Board of Directors. They shall be made available to the public as provided for by law and Consob regulations at least twenty-one days before the date set for the Shareholders' Meeting at first or single call. Each shareholder may, severally or jointly, submit and vote on a single slate only. Controlling persons, subsidiaries and companies under common control may not submit or participate in the submission of other slates, nor can they vote on them, either directly or through nominees or trustees. As used herein, subsidiaries are those companies referred to in Article 93 of Legislative Decree No. 58 of February 24, 1998. Each candidate may stand on a single slate, on penalty of disqualification. Only those shareholders who, severally or jointly, represent at least 1% of share capital or any other threshold established by Consob regulations shall be entitled to submit a slate. Ownership of the minimum holding needed to submit slates shall be determined with regard to the shares registered to the shareholder on the day on which the slates are filed with the Company. Related certification may be submitted after the filing, provided that submission takes place by the deadline set for the publication of the slates by the Company.

At least one director, if there are no more than five directors, or at least three directors, if there are more than five, shall satisfy the independence requirements established for the members of the board of statutory auditors of listed companies.

The candidates meeting such independence requirements shall be expressly identified in each slate.

All candidates shall also satisfy the integrity requirements established by applicable law.

Slates that contain three or more candidates shall include candidates of both genders, as specified in the notice calling the meeting, in order to comply with the applicable gender-balance legislation. When the number of members of the less-represented gender must, by law, be at least three, the slates competing to appoint the majority of the members of the Board of Directors must include at least two candidates of the less-represented gender.

Together with the filing of each slate, on penalty of inadmissibility, the following shall also be filed: the curriculum vitae of each candidate, statements of each candidate accepting his/her nomination and affirming, under his/her personal responsibility, the absence of any grounds making him/her ineligible or incompatible for such position and that he/she satisfies the afore mentioned requirements of integrity and independence (where applicable).

The appointed directors shall notify the Company if they should no longer satisfy the independence and integrity requirements or if cause for ineligibility or incompatibility should arise.

The Board of Directors shall periodically evaluate the independence and integrity of its members and whether cause for ineligibility or incompatibility has arisen. If the integrity or independence requirements established by applicable legislation should no longer be met by a director or if cause for ineligibility or incompatibility should have arisen, the Board of Directors shall declare the director disqualified and replace him/her or shall invite him/her to rectify the situation of incompatibility by a deadline set by the Board itself, on penalty of disqualification.

Directors shall be elected in the following manner:

a) seven-tenths of the directors to be elected shall be drawn from the slate that receives the most votes of the shareholders in the order in which they appear on the slate, rounded off in the event of a decimal number to the next lowest whole number;

b) the remaining directors shall be drawn from the other slates. Said slates shall not be connected in any way, directly or indirectly, to the shareholders who have submitted or voted the slate that receives the largest number of votes. For this purpose, the votes received by each slate shall be divided by one or two or three depending upon the number of directors to be elected. The quotients, or points, thus obtained shall be assigned progressively to candidates of each slate in the order given in the slates themselves. The candidates of all the slates shall be ranked by the points assigned in single list in descending order. Those who receive the most points shall be elected. In the event that more than one candidate receives the same number of points, the candidate elected shall be the person from the slate that has not hitherto had a director elected or that has elected the least number of directors. In the event that none of the slates has yet had a director elected or that all of them have had the same number of directors elected, the candidate among all such slates who has received the highest number of votes shall be elected. In the event of equal slate votes and equal points, the entire Shareholders' Meeting shall vote again and the candidate elected shall be the person who receives a simple majority of the votes;

c) if the minimum number of independent directors required under these By-laws has not been elected following the above procedure, the points to be assigned to the candidates draw from the slates shall be calculated by dividing the number of votes received by each slate by the ordinal number of each of these candidates; the candidates who do not meet the requirements of independence with the fewest points from among the candidates drawn from all of the slates shall be replaced, starting from the last, by the independent candidates, from the same slate as the replaced candidate (following the order in which they are listed), otherwise by persons meeting the independence requirements appointed in accordance with the procedure set out in letter d). In cases where candidates from different lists have received the same number of points, the candidate from the slate from which the largest number of directors has been drawn or, subordinately, the candidate drawn from the slate receiving the lowest number of votes, or, in the event of a tie vote, the candidate that receives the fewest votes of the Shareholders' Meeting in a run-off election, shall be replaced;

c-bis) if the application of the procedure set out in letters a) and b) does not permit compliance with the gender-balance rules, the points to attribute to each candidate drawn from the slate shall be calculated by dividing the number of votes received by each slate by the ordinal number of each of these candidates; the candidate of the over-represented gender with the fewest points from among the candidates drawn from all of the slates shall be replaced, without prejudice to the compliance with the required minimum number of independent directors, by the member of the less-represented gender who may be listed (with the next highest ordinal number) on the same slate as the candidate to be replaced, otherwise by a person to be appointed following the procedure set out in letter d). In cases where candidates from different lists have received the same minimum number of points, the candidate from the slate from which the largest number of directors has been drawn or, subordinately, the candidate drawn from the slate receiving the fewest number of votes, or, in the event of a tie vote, the candidate that receives the fewest votes of the Shareholders' Meeting in a run-off election, shall be replaced; and

d) to appoint directors who for any reason were not appointed pursuant to the above procedures, the Shareholders' Meeting shall resolve, with the majorities required by law, to ensure that the composition of the Board of Directors complies with applicable law and the By-laws.

The slate voting procedure shall apply only to the election of the entire Board of Directors.

17.4 The Shareholders' Meeting may, during the Board's term of office, change the number of members of the Board of Directors, within the limits established in the first paragraph of this Article, and make the related appointments. The terms of directors so elected shall expire at the same time as those of the directors already in office.

17.5 If, during the year, the office of one or more directors should be vacated, he/she shall be replaced in accordance with Article 2386 of the Italian Civil Code. In any case, compliance with the required minimum number of independent directors and the applicable rules concerning gender-balance shall not be affected.

If a majority of the directors should vacate their offices, the entire Board shall be considered to have resigned, and the Board shall promptly call a Shareholders' Meeting to elect a new Board.

17.6 The Board may establish internal committees to provide advice and proposals on specific issues.

ARTICLE 18

18.1 If the Shareholders' Meeting has not appointed a Chairman, the Board shall elect one from among its members.

18.2 The Board, acting upon a proposal of the Chairman, shall appoint a Secretary, who need not be affiliated with the Company.

ARTICLE 19

19.1 The Board shall meet in the place indicated in the meeting notice whenever the Chairman or, in the event of his absence or impediment, the Chief Executive Officer deems necessary, or when a written request has been made by the majority of its members. The Board of Directors may also be convened pursuant to Article 28.4 of these By-laws. The meetings of the Board of Directors may be held by video or teleconference on the condition that all of the participants in the meeting can be identified and that all can follow and participate in real time in the discussion of the matters being addressed. The meeting shall be considered duly held in the place where the Chairman and the Secretary are present.

19.2 Notice shall normally be given at least five days in advance of the meeting. In urgent circumstances, the period of notice may be shorter. The Board of Directors shall decide how its meetings are to be convened.

19.3 The Board of Directors shall also be convened when so requested by at least two directors or by one director if the Board consists of three directors, to decide on a specific matter deemed to be of particular importance regarding the management of the Company. Said matter shall be specified in the request.

ARTICLE 20

20.1 The Chairman of the Board or, in his absence, the eldest director in attendance shall chair the meeting.

ARTICLE 21

21.1 For a Board meeting to be valid, a majority of serving directors must be present.

21.2 Resolutions shall be approved by a majority of the votes of the directors present; in the event of a tie, the person who chairs the meeting shall have a casting vote.

ARTICLE 22

22.1 The resolutions of the Board of Directors shall be registered in the minutes, which shall be recorded in a book kept for that purpose pursuant to the provisions of law, and said minutes shall signed by the Chairman of the meeting and by the Secretary.

22.2 Copies of the minutes shall be considered bona fide if they are signed by the Chairman or the person acting in place of the Chairman and countersigned by the Secretary.

ARTICLE 23

23.1 The Board of Directors is invested with the fullest powers for the ordinary and extraordinary management of the Company and, in particular, has the power to perform all acts it deems advisable for the implementation and achievement of the corporate purpose, with the sole exception of acts that the law or these By-laws reserve to the Shareholders' Meeting.

23.2 The Board of Directors shall decide the following matters:

- the merger and proportional demerger of companies in which the Company owns shares or other equity holdings representing at least 90% of the share capital;
- the establishment and closing of branches; and
- the amendment of the By-laws to comply with the provisions of law.

23.3 The Board of Directors and the Chief Executive Officer shall promptly report to the Board of Statutory Auditors at least every three months and in any event at the time of the meetings of the Board of Directors, on the activity carried out and on the transactions with the most significant impact on performance and the financial position carried out by the Company and its subsidiaries. In particular, they shall report to the Board of Statutory Auditors those transactions in which they have an interest, either on their own behalf or on behalf of third parties.

ARTICLE 24

24.1 The Board of Directors may delegate its powers to one of its members, within the limits set forth in Article 2381 of the Italian Civil Code. The Board may, in addition, delegate powers to the Chairman to identify and promote integrated projects and international agreements of strategic importance. The Board of Directors may revoke delegated powers at any time, proceeding, in the case of revocation of the powers delegated to the Chief Executive Officer, to appoint another Chief Executive Officer at the same time. The Board of Directors, acting upon a proposal of the Chairman and in agreement with the Chief Executive Officer, may confer powers for individual acts or categories of acts on other members of the Board of Directors. The Chairman and the Chief Executive Officer, within the limits of the authority attributed to them, may delegate and empower Company employees or third parties to represent the Company for individual acts or specific categories of acts.

Further, acting upon proposal of the Chief Executive Officer and in agreement with the Chairman, the Board of Directors may also appoint one or more General Managers (Chief Operating Officers) and determine the powers to be conferred on them, once it has been ascertained that they fulfill the

integrity requirements set by law. The Board of Directors shall periodically check the continuing compliance with integrity requirements of the General Managers (Chief Operating Officers). Failure to satisfy these requirements shall result in disqualification from the position.
Acting upon a proposal of the Chief Executive Officer, in agreement with the Chairman and with the approval of the Board of Statutory Auditors, the Board of Directors shall appoint the Officer responsible for preparing financial reporting documents.
The Officer responsible for preparing financial reporting documents shall be selected from among those persons who, for at least three years, have performed:

a) administration, control or management activities in companies listed on regulated Stock Exchanges in Italy or other European Union countries or other OECD countries with a share capital of no less than euro 2 million; or
b) statutory audit activities in companies indicated in letter a) above; or
c) professional activities or university teaching activities in the financial or accounting sectors; or
d) management functions in public or private entities with financial, accounting or control expertise.

The Board of Directors shall ensure that the Officer responsible for preparing the financial reporting documents has adequate powers and means to perform the duties of the position and that administrative and accounting procedures are being followed.

ARTICLE 25

25.1 The Chairman and the Chief Executive Officer are severally vested with powers of legal representation of the Company before any judicial or administrative authority and with respect to third parties and exercise signature powers on behalf of the Company.

ARTICLE 26

26.1 The Chairman and the members of the Board of Directors shall be entitled to compensation to be determined by the ordinary Shareholders' Meeting. Said resolution, once taken, shall remain valid for subsequent financial years until the Shareholders' Meeting should decide otherwise.

ARTICLE 27

27.1 The Chairman:

a) represents the Company pursuant to Article 25.1;
b) chairs the Shareholders' Meeting pursuant to Article 15.1;
c) calls and chairs meetings of the Board of Directors pursuant to Articles 19.1 and 20.1;
d) verifies that Board resolutions are implemented; and
e) exercises the powers delegated to him by the Board of Directors pursuant to Article 24.1.

Part VI – The Board of Statutory Auditors

ARTICLE 28

28.1 The Board of Statutory Auditors shall consist of five standing members and two alternate members, chosen from among persons who satisfy the professional and integrity requirements established by the Ministry of Justice Decree No. 162 of March 30, 2000.
Pursuant to the afore mentioned decree, the fields closely connected with the business of the Company are: commercial law, business economics and corporate finance.
Similarly, the sectors closely connected with the business of the Company are engineering and geology.
The Statutory Auditors may be appointed as members of the administrative and control bodies of other companies within the limits set by Consob regulations.

28.2 The Board of Statutory Auditors shall be appointed by the Shareholders' Meeting on the basis of slates presented by shareholders. The candidates shall be listed on the slates in numerical order in a number no greater than the number of members of the body to be appointed.
The procedures set out in Article 17.3 and the provisions issued in Consob regulations shall apply to the submission, filing and publication of candidate slates.
Slates shall be divided into two sections: the first containing candidates for appointment as standing Statutory Auditors and the second containing candidates for appointment as alternate Statutory Auditors. At least the first candidate in each section must be entered in the register of auditors and have carried out statutory audit activities for no less than three years.
Slates that, considering both sections together, contain three or more candidates shall include, in the section for standing Statutory Auditors, candidates of both genders, as specified in the notice calling the Shareholders' Meeting, in order to comply with the applicable gender-balance legislation. If the section for alternate Statutory Auditors on these slates contains two candidates, they must be of different genders. When the number of members of the less-represented gender must, by law, be at least one, such requirement shall apply only to slates competing to appoint the majority of the members of the Board of Statutory Auditors.
Three standing Statutory Auditors and one alternate Statutory Auditor shall be drawn from the slate that receives the majority of votes. The other two standing Statutory Auditors and the other alternate Statutory Auditor shall be appointed using the procedures set out in Article 17.3, letter b) of the By-laws. Said procedures shall be applied separately to each section of the other slates.

The Shareholders' Meeting shall appoint the Chairman of the Board of Statutory Auditors from among the standing Statutory Auditors appointed in accordance with Article 17.3, letter b) of these By-laws.

Where the application of the procedure set out above does not permit compliance with the gender-balance rules for standing Statutory Auditors, the points to attribute to each candidate drawn from the standing Statutory Auditor sections of the various slates shall be calculated by dividing the number of votes received by each slate by the ordinal number of each of these candidates; the candidate of the over-represented gender with the fewest points from among the candidates drawn from all of the slates shall be replaced by the member of the less-represented gender who may be listed (with the next highest ordinal number) in the standing Statutory Auditor section on the same slate as the candidate to be replaced or, subordinately, in the alternate Statutory Auditor section of the same slate as the candidate to be replaced (in such case, the latter shall take the position of the alternate candidate that replaces him/her). If this does not permit compliance with the gender-balance rules, he/she shall be replaced by a person chosen by the Shareholders' Meeting with the majority required by law, so as to ensure that the membership of the Board of Statutory Auditors complies with the law and the By-laws. In cases where candidates from different lists have received the same number of points, the candidate from the slate from which the largest number of Statutory Auditors has been drawn or, subordinately, the candidate drawn from the slate receiving the fewest number of votes, or, in the event of a tie vote, the candidate that receives the fewest votes of the Shareholders' Meeting in a run-off election, shall be replaced.

For the appointment of Statutory Auditors who, for any reason, are not appointed using the above procedures, the Shareholders' Meeting shall resolve, with the majorities required by law, in such a manner as to ensure that the membership of the Board of Statutory Auditors complies with the law and the By-laws.

The slate voting procedure shall apply only in case of appointment of the entire Board of Statutory Auditors.

Should a standing Statutory Auditor from the slate that received a majority of the votes be replaced, the replacement shall be the alternate Statutory Auditor from the same slate; should a standing Statutory Auditor from other slates be replaced, the replacement shall be the alternate Statutory Auditor from those other slates. If the replacement results in non-compliance with gender-balance rules, the Shareholders' Meeting shall be called as soon as possible to approve the necessary resolutions to ensure compliance.

28.3 Statutory Auditors may be re-elected.

28.4 Subject to prior notification of the Chairman of the Board of Directors, the Board of Statutory Auditors may call Shareholders' Meetings and meetings of the Board of Directors. The power to call a meeting of the Board of Directors may be exercised individually by each member of the Board of Statutory Auditors; at least two Statutory Auditors are required to call Shareholders' Meetings.

The meetings of the Board of Statutory Auditors may be held by video or teleconference on the condition that all of the participants in the meetings can be identified and that all can follow and participate in real time in the discussion of the matters being addressed. The meeting shall be considered duly held in the place where the Chairman and the Secretary are present.

Part VII – Financial Statements and Profits

ARTICLE 29

29.1 The Company's financial year ends on December 31 of each year.

29.2 At the end of each financial year, the Board of Directors shall prepare the Company financial statements in compliance with the provisions of law.

29.3 The Board of Directors may distribute interim dividends to the shareholders during the financial year.

ARTICLE 30

30.1 Entitlement to dividends not collected within five years of the day on which they become payable shall lapse in favor of the Company and such dividends shall be allocated to reserves.

Part VIII – Winding Up and Liquidation of the Company

ARTICLE 31

31.1 In the event the Company is wound up, the Shareholders' Meeting shall decide the manner of its liquidation and appoint one or more liquidators, establishing their powers and remuneration.

Part IX – General Provisions

ARTICLE 32

32.1 For all matters not expressly governed by these By-laws, the Italian Civil Code and applicable special laws shall apply.

32.2 Pursuant to Article 3, paragraph 2, of Decree Law No. 332 of May 31, 1994, ratified with amendments by Law No. 474 of July 30, 1994, Article 6.1, sixth paragraph, of these By-laws shall not apply to the shareholdings owned by the Ministry of the Economy and Finance, public entities or entities they control.

ARTICLE 33

33.1 The Company retains all legal relationships in respect of assets and liabilities held by the public agency Ente Nazionale Idrocarburi before its transformation.

ARTICLE 34

34.1 The provisions of Articles 17.3, 17.5 and 28.2 directed to ensure compliance with applicable gender-balance legislation shall apply to the first three elections of the Board of Directors and Board of Statutory Auditors after August 12, 2012.

EXHIBIT 8

See “Item 18 — note 37 — Other information about investments — Information on Eni’s investments as of December 31, 2018 — of the Notes on Consolidated Financial Statements”.

Exhibit 11

Code of Ethics

Approved by the Board of Directors of Eni SpA on November 23, 2017

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Eni's Code of Ethics

INTRODUCTION

Eni[1] is an internationally oriented industrial group which, because of its size and the importance of its activities, plays a significant role in the marketplace and in the economic development and welfare of the individuals who work or collaborate with Eni and of the communities where it is present.

The complexity of the situations in which Eni operates, the challenges of sustainable development and the need to take into consideration the interests of all people having a legitimate interest in the corporate business ("Stakeholders"), strengthen the importance to clearly define the values that Eni accepts, acknowledges and shares as well as the responsibilities it assumes, contributing to a better future for everybody.

For this reason the new Eni's Code of Ethics ("Code" or "Code of Ethics") has been devised. Compliance with the Code by Eni's directors, statutory auditors, management and employees as well as by all those who operate in Italy and abroad for achieving Eni's objectives ("Eni's People"), each within their own functions and responsibilities, is of paramount importance – also pursuant to legal and contractual provisions governing the relationship with Eni – for Eni's efficiency, reliability and reputation, which are all crucial factors for its success and for improving the social situation in which Eni operates.

Eni undertakes to promote awareness of the Code among Eni's People and the other *Stakeholders* and their constructive contribution to its principles Eni undertakes to take into account any suggestions and observations by the *Stakeholders,* with the aim of confirming or supplementing the Code.

Eni carefully checks for compliance with the Code by providing suitable information, prevention and control tools and ensuring transparency in all transactions and behaviours by taking corrective measures if and as required. The Watch Structure of Eni SpA performs the functions of guarantor of the Code of Ethics ("Guarantor").

The Code is brought to the attention of every person or body having business relations with Eni.

(1) "Eni" means Eni spa and its direct and indirect Subsidiaries, in Italy and abroad.

I. GENERAL PRINCIPLES: SUSTAINABILITY AND CORPORATE RESPONSIBILITY

Compliance with the law, regulations, statutory provisions, self-regulatory codes, ethical integrity and fairness, is a constant commitment and duty of all Eni's People, and characterizes the conduct of its entire organization.

Eni's business and corporate activities have to be carried out in a transparent, honest and fair way, in good faith, and in full compliance with competition protection rules.

Eni undertakes to maintain and strengthen a governance system in line with international best practice standards, able to deal with the complex situations in which Eni operates, and with the challenges to face for sustainable development.

Systematic methods for involving Stakeholders are adopted, fostering dialogue on sustainability and corporate responsibility.

In conducting both its activities as an international company and those with its partners, Eni stands up for the protection and promotion of human rights, inalienable and fundamental prerogatives of human beings and basis for the establishment of societies founded on principles of equality, solidarity, repudiation of war, and for the protection of civil and political rights, of social, economic and cultural rights and the so-called third generation rights (self-determination right, right to peace, right to development and protection of the environment).

Any form of discrimination, corruption, forced or child labour is rejected. Particular attention is paid to the acknowledgement and safeguarding of the dignity, freedom and equality of human beings, to protection of labour and of the freedom of trade union association, of health, safety, the environment and biodiversity, as well as the set of values and principles concerning transparency, energy efficiency and sustainable development, in accordance with International Institutions and Conventions.

In this respect Eni operates within the reference framework of the United Nations Universal Declaration of Human Rights, the Fundamental Conventions of the ILO – International Labor Organization – and the OECD Guidelines on Multinational Enterprises.

All Eni's People, without any distinction or exception whatsoever, respect the principles and contents of the Code in their actions and behaviours while performing their functions and according to their responsibilities, because compliance with the Code is fundamental for the quality of their working and professional performance. Relationships among Eni's People, at all levels, must be characterized by honesty, fairness, cooperation, loyalty and mutual respect.

The belief that one is acting in favour or to the advantage of Eni can never, in any way, justify, not even in part, any behaviours that conflict with the principles and contents of the Code.

II. BEHAVIOUR RULES AND RELATIONS WITH STAKEHOLDERS

1. ETHICS, TRANSPARENCY, FAIRNESS, PROFESSIONALISM

In conducting its business, Eni is inspired by and complies with the principles of loyalty, fairness, transparency, efficiency and an open market, regardless of the importance level of the transaction in question.

Any action, transaction and negotiation performed and, generally, the conduct of Eni's People in the performance of their duties is inspired by the highest principles of fairness, completeness and transparency of information and legitimacy, both in form and substance, as well as clarity and truthfulness of all accounting documents, in compliance with the applicable laws in force and internal regulations.

All Eni's activities have to be performed with the utmost care and professional skill, with the duty to provide skills and expertise adequate to the tasks assigned, and to act in a way capable to protect Eni's image and reputation. Without prejudice to the compliance with applicable laws and obligations arising out from the adhesion to the principles contained in the Code of Conduct, the corporate objectives, as well as the proposal and implementation of projects, investments and actions, have to be aimed at improving the company's assets, management, technological and information level in the long term, and at creating value and welfare for all Stakeholders.

Bribes, illegitimate favours, collusion, requests for personal benefits for oneself or others, either directly or through third parties, are prohibited without any exception.

It is prohibited to pay or offer, directly or indirectly, money and material benefits and other advantages of any kind to third parties, whether representatives of governments, public officers and public servants or private employees, in order to influence or remunerate the actions of their office.

Commercial courtesy, such as small gifts or forms of hospitality, is only allowed when its value is small and it does not compromise the integrity and reputation of either party, and cannot be construed by an impartial observer as aimed at obtaining undue advantages. In any case, these expenses must always be authorized by the designated managers as per existing internal rules, and be accompanied by appropriate documentation.

It is forbidden to accept money from individuals or companies that have or intend to have business relations with Eni. Anyone who receives proposals of gifts or special or hospitality treatment that cannot be considered as commercial courtesy of small value, or requests therefore by third parties, shall reject them and immediately inform their superior, or the body they belong to, as well as the Guarantor.

Eni shall properly inform all third parties about the commitments and obligations provided for in the Code, require third parties to respect the principles of the Code relevant to their activities and take proper internal actions and, if the matter is within its own competence, external actions in the event that any third party should fail to comply with the Code.

2. RELATIONS WITH SHAREHOLDERS AND WITH THE MARKET

2.1. Value for shareholders, efficiency, transparency

The internal structure of Eni and the relations with the parties directly and indirectly taking part in its activities are organized according to rules able to ensure management reliability and a fair balance between the management's powers and the interests of shareholders and of the other Stakeholders in general as well as transparency and market traceability of management decisions and general corporate events which may considerably influence the market value of the financial instruments issued.

Within the framework of the initiatives aimed at maximizing the value for shareholders and at guaranteeing transparency of the management's work, Eni defines, implements and progressively adjusts a coordinated and homogeneous set of behaviour rules concerning both its internal organizational structure and relations with shareholders and third parties, in compliance with the highest corporate governance standards at national and international level, based on the awareness that the company's capacity to impose efficient and effective functioning rules upon itself is a fundamental tool for strengthening its reputation in terms of reliability and transparency as well as Stakeholders' trust.

Eni deems it necessary that shareholders are enabled to participate in decisions which come within the limits of their competence and make informed choices. Therefore, Eni undertakes to ensure maximum transparency and timeliness of information communicated to shareholders and to the market, by means of the corporate internet site, too, in compliance with the laws and regulations applicable to listed companies.

Eni also undertakes to keep in due consideration the legitimate remarks expressed by shareholders whenever they are entitled to do so.

2.2. Self-Regulatory Code

The main corporate governance rules of Eni are contained in the Corporate Governance Code for listed companies, to which Eni adheres and which is referred to herein as may be required.

2.3. Company information

Eni ensures the correct management of company information, by means of suitable procedures for in-house management and communication to the outside, with particular reference to privileged information.

2.4. Privileged information

All Eni's People are required, while performing the tasks entrusted to them, to properly manage privileged information such as to know and comply with corporate procedures referring to market abuse. Any conduct liable to constitute market abuse or facilitate its commission is specifically prohibited. In any case, the purchase or sale of shares of Eni or of companies outside Eni shall always be based on absolute and transparent fairness.

2.5. Information means

It is responsibility of Eni to provide third parties with true, prompt, transparent and accurate information.

Relations with the media are exclusively dealt with by the departments and managers specifically appointed to do so; information to be supplied to media representatives, as well as the undertaking to provide such information, have to be agreed upon beforehand by Eni's People with the relevant Eni Corporate structure.

3. RELATIONS WITH INSTITUTIONS, ASSOCIATIONS, LOCAL COMMUNITIES

Eni encourages dialogue with Institutions and with organized associations of civil society in all the countries where it operates.

3.1 Authorities and Public Institutions

Eni, through its People, actively and fully cooperates with Authorities.

Eni's People, as well as external collaborators whose actions may somehow be referred to Eni, must have behaviours towards the Public Administration characterized by fairness, transparency and traceability. These relations have to be exclusively dealt with by the departments and individuals specifically appointed to do so, in compliance with approved plans and corporate procedures.

The departments of the subsidiaries concerned shall coordinate with the relevant Eni Corporate structure for assessing the quality of the interventions to be carried out and for the sharing, implementing and monitoring of their actions.

It is forbidden to make, induce or encourage false statements to Authorities.

3.2 Political organizations and trade unions

Eni does not make any direct or indirect contributions in whatever form to political parties, movements, committees, political organizations and trade unions, nor to their representatives and candidates.

3.3 Development of local Communities

Eni is committed to actively contribute to promoting the quality of life, the socio-economic development of the communities where Eni operates and to the development of their human resources and capabilities, while conducting its business activities according to standards that are compatible with fair commercial practices.

Eni's activities are carried out in the awareness of the social responsibility that Eni has towards all of its Stakeholders and in particular the local communities in which it operates, in the belief that the capacity for dialogue and interaction with civil society constitutes an important asset for the company. Eni respects the cultural, economic and social rights of the local communities in which it operates and undertakes to contribute, as far as possible, to their exercise, with particular reference to the right to adequate nutrition, drinking water, the highest achievable level of physical and mental health, decent dwellings, education, abstaining from actions that may hinder or prevent the exercise of such rights.

Eni promotes transparency of the information addressed to local communities, with particular reference to the topics that they are most interested in. Forms of continuous and informed consultancy are also promoted, through the relevant Eni structures, in order to take into due consideration the legitimate expectations of local communities in conceiving and conducting corporate activities and in order to promote a proper redistribution of the profits deriving from such activities.

Eni therefore undertakes to promote the knowledge of its corporate values and principles, at every level of its organization, also through adequate control procedures, and to protect the rights of local communities, with particular reference to their culture, institutions, ties and life styles.

Within the framework of their respective responsibilities, Eni's People are required to participate in the definition of single initiatives in compliance with Eni's policies and intervention programs, to implement them according to criteria of absolute transparency and support them as an integral part of Eni's objectives.

3.4 Promotion of "non profit" activities

The philanthropic activity of Eni is in line with its vision and attention to sustainable development.

Eni therefore undertakes to foster and support, as well as to promote among its People, its "non profit" activities which demonstrate the company's commitment to help meet the needs of those communities where it operates.

4. RELATIONS WITH CUSTOMERS AND SUPPLIERS

4.1 Customers and consumers

Eni pursues its business success on markets by offering quality products and services under competitive conditions while respecting the rules protecting fair competition.

Eni undertakes to respect the right of consumers not to receive products harmful to their health and physical integrity and to get complete information on the products offered to them.

Eni acknowledges that the esteem of those requesting products or services is of primary importance for success in business. Business policies are aimed at ensuring the quality of goods and services, safety and compliance with the precautionary principle. Therefore, Eni's People shall:

- comply with in-house procedures concerning the management of relations with customers and consumers;
- supply, with efficiency and courtesy, within the limits set by the contractual conditions, high-quality products meeting the reasonable expectations and needs of customers and consumers;
- supply accurate and exhaustive information on products and services and be truthful in advertisements or other kind of communication, so that customers and consumers can make informed decisions.

4.2 Suppliers and external collaborators

Eni undertakes to look for suppliers and external collaborators with suitable professionalism and committed to sharing the principles and contents of the Code and promotes the establishment of long-lasting relations for the progressive improvement of performances while protecting and promoting the principles and contents of the Code.

In relationships regarding tenders, procurement and, generally, the supply of goods and/or services and of external collaborations (including consultants, agents, etc.), Eni's People shall:

- follow internal procedures concerning selection and relations with suppliers and external collaborators and abstain from excluding any supplier meeting requirements from bidding for Eni's orders; adopt appropriate and objective selection methods, based on established, transparent criteria;
- secure the cooperation of suppliers and external collaborators in guaranteeing the continuous satisfaction of customers and consumers, to an extent adequate to that legitimately expected by them, in terms of quality, costs and delivery times;
- use as much as possible, in compliance with the laws in force and the criteria for legality of transactions with related parties, products and services supplied by Eni companies at arm's length and market conditions;
- state in contracts the Code acknowledgement and the obligation to comply with the principles contained therein;
- comply with, and demand compliance with, the conditions contained in contracts;
- maintain a frank and open dialogue with suppliers and external collaborators in line with good commercial practice; promptly inform superiors, and the Guarantor, about any possible violations of the Code;
- inform the relevant Eni Corporate structure about any serious problems that may arise with a particular supplier or external collaborator, in order to evaluate possible consequences for Eni.

The remuneration to be paid shall be exclusively proportionate to the services to be rendered and described in the contract and payments shall not be allowed to any party different from the contract party nor in a third Country different from the one of the parties or where the contract has to be performed[2].

5. MANAGEMENT, EMPLOYEES AND COLLABORATORS OF ENI

5.1. Development and protection of Human Resources

People are basic components in the company's life. The dedication and professionalism of management and employees represent fundamental values and conditions for achieving Eni's objectives.

Eni is committed to developing the abilities and skills of management and employees so that their energy and creativity can have full expression for the fulfilment of their potential in their working performance, such as to protect working conditions as regards both mental and physical health and dignity. Undue pressure or discomfort is not allowed, while appropriate working conditions promoting development of personality and professionalism are fostered.

(2) For the purposes of application of the ban, third countries do not include States where a company/entity, counter-party of Eni, has established its centralized cash management system and/or where the same has established, in whole or in part, its headquarters, offices or business units functional and necessary for the execution of the contract, in each case subject to all the additional control tools provided by internal regulatory instruments concerning the selection of counter-parties and payments.

Eni undertakes to offer, in full compliance with applicable legal and contractual provisions, equal opportunities to all its employees, making sure that each of them receives a fair statutory and wage treatment exclusively based on merit and expertise, without discrimination of any kind. Competent departments shall:

- adopt in any situation criteria of merit and ability (and anyhow strictly professional) in all decisions concerning human resources;
- select, hire, train, compensate and manage human resources without discrimination of any kind;
- create a working environment where personal characteristics or beliefs do not give rise to discrimination and which allows the serenity of all Eni's People.

Eni wishes that Eni's People, at every level, cooperate in maintaining a climate of common respect for a person's dignity, honour and reputation. Eni shall do its best to prevent attitudes that can be considered as offensive, discriminatory or abusive. In this regard, any behaviours outside the working place which are particularly offensive to public sensitivity are also deemed relevant.

In any case, any behaviours constituting physical or moral violence are forbidden without any exception.

5.2. Knowledge Management

Eni promotes culture and the initiatives aimed at disseminating knowledge within its structures, and at pointing out the values, principles, behaviours and contributions in terms of innovation of professional families in connection with the development of business activities and to the company's sustainable growth.

Eni undertakes to offer tools for interaction among the members of professional families, working groups and communities of practice, as well as for coordination and access to know-how, and shall promote initiatives for the growth, dissemination and systematization of knowledge relating to the core competences of its structures and aimed at defining a reference framework suitable for guaranteeing operating consistency.

All Eni's People shall actively contribute to Knowledge Management as regards the activities that they are in charge of, in order to optimize the system for knowledge sharing and distribution among individuals.

5.3. Corporate security

Eni engages in the study, development and implementation of strategies, policies and operational plans aimed at preventing and overcoming any intentional or non-intentional behaviour which may cause direct or indirect damage to Eni's People and/or to the tangible and intangible resources of the company. Preventive and defensive measures, aimed at minimizing the need for an active response – always in proportion to the attack – to threats to people and assets, are favoured.

All Eni's People shall actively contribute to maintaining an optimal corporate security standard, abstaining from unlawful or dangerous behaviours, and reporting any possible activities carried out by third parties to the detriment of Eni's assets or human resources to superiors or to the body they belong to, as well as to the relevant Eni Corporate structure.

In any case requiring particular attention to personal safety, it is compulsory to strictly follow the indications in this regard supplied by Eni, abstaining from behaviours which may endanger one's own safety or the safety of others, promptly reporting any danger for one's own safety, or the safety of third parties, to one's superior.

5.4. Harassment or mobbing in the workplace

Eni supports any initiatives aimed at implementing working methods for the achievement of a better organization.

Eni demands that there shall be no harassment or mobbing behaviours in personal working relationships either inside or outside the company. Such behaviours are all forbidden, without exceptions. Such harassment is for instance:

- the creation of an intimidating, hostile, isolating or in any case discriminatory environment for individual employees or groups of employees;
- unjustified interference in the work performed by others;
- the placing of obstacles in the way of the work prospects and expectations of others merely for reasons of personal competitiveness or because of other employees.

Any form of violence or harassment, either sexual harassment or harassment based on personal and cultural diversity, is forbidden. Such harassment is for instance:

- subordinating decisions on someone's working life to the acceptance of sexual attentions, or personal and cultural diversity;
- encouraging employees to sexual favours through the influence of a role;
- proposing private interpersonal relations, despite express or reasonably obvious non-acceptance;
- alluding to disabilities and physical or psychic impairment, or to forms of cultural, religious or sexual diversity.

5.5. Abuse of alcohol or drugs and no smoking

All Eni's People shall personally contribute to promoting and maintaining a climate of common respect in the workplace; particular attention is paid to respect of the feelings of others.

Eni will therefore consider individuals who work under the effect of alcohol or drugs, or substances with similar effect, during the performance of their work activities and in the workplace, as being aware of the risk they cause. Chronic addiction to such substances, when it affects work performance, shall be considered similar to the above mentioned events in terms of contractual consequences; Eni is committed to favour social action in this field as provided for by employment contracts.

It is forbidden to:

- hold, consume, offer or give for whatever reason, drugs or substances with similar effect, at work and in the workplace;
- smoke in the workplace. Eni supports voluntary initiatives addressed to People to help them quit smoking and, in identifying possible smoking areas, shall take into particular consideration the condition of those suffering physical discomfort from exposure to smoke in the workplace shared with smokers and requesting to be protected from "passive smoking" in their place of work.

III. TOOLS FOR IMPLEMENTING THE CODE OF ETHICS

1. INTERNAL CONTROL AND RISK MANAGEMENT SYSTEM

Eni is committed to promoting and maintaining an adequate internal control and risk management system, by adopting and implementing all useful instruments to direct, manage and monitor business activities with the aim of ensuring compliance with laws and company procedures, protecting corporate assets, efficiently and effectively managing activities and providing accurate and complete accounting and financial data, as well ensuring a proper process of identification, measurement, management and monitoring of main business risks.

The responsibility for implementing an effective system of internal control and risk management is shared at every level of Eni's organizational structure; therefore, all Eni's People, according to their functions and responsibilities, shall define and actively participate in the correct functioning of the system of internal control and risk management.

Eni promotes the dissemination, at every level of its organization, of policies and procedures characterized by awareness of the existence of controls and by an informed and voluntary control oriented mentality; consequently, Eni's management in the first place and all Eni's People in any case shall contribute to and participate in Eni's system of internal control and risk management and, with a positive attitude, involve its collaborators in this respect.

Each employee shall be held responsible for the corporate tangible and intangible assets relevant to his/her job. No employee can make, or let others make, improper use of assets and equipment belonging to Eni.

Any practices and attitudes linked to the perpetration or to the participation in the perpetration of frauds are forbidden without any exception.

Control and watch structures, Eni Internal Audit department and appointed auditing companies shall have full access to all data, documents and information necessary to perform their own relevant activities.

1.1 Conflicts of interest

Eni acknowledges and respects the right of its People to take part in investments, business and other kinds of activities other than the activity performed in the interest of Eni, provided that such activities are permitted by law and are compatible with the obligations assumed towards Eni. Eni adopts internal regulatory instruments that ensure transparency and fairness, substantive and procedural, of the transactions involving interests of Directors and Statutory Auditors and transactions with related parties.

Eni's management and employees shall avoid and report any conflicts of interest between personal and family economic activities and their tasks within the company. In particular, everyone shall point out any specific situations and activities of economic or financial interest (owner or member) to them or, as far as they know, of economic or financial interest to relatives of theirs or relatives by marriage within the 2nd degree of kinship, or to persons actually living with them, also involving suppliers, customers, competitors, third parties, or the relevant controlling companies or subsidiaries, and shall point whether they perform corporate administration or control or management functions therein.

Moreover, conflicts of interest are determined by the following situations:

- using one's position in the company or the information or business opportunities acquired during one's work, to undue personal advantage or to that of third parties;
- carrying out of work activities by employees and/or their family members at suppliers, subcontractors, competitors.

In any case, Eni's management and employees shall avoid any situation and activity where a conflict with the Company's interests may arise, or which can interfere with their ability to make impartial decisions in the best interests of Eni and in full accordance with the principles and contents of the Code, or in general with their ability to fully comply with their functions and responsibilities. Any situation that may constitute or give rise to a conflict of interest shall be immediately reported to one's superior within management, or to the body one belongs to, and to the Guarantor. Furthermore, the party concerned shall abstain from taking part in the operational/decision-making process, and the relevant superior within management, or the relevant body, shall:

- identify the operational solutions suitable for ensuring, in the specific case, transparency and fairness of behaviours in the performance of activities;
- transmit to the parties concerned – and for information to one's superior, as well as to the Guarantor – the necessary written instructions;
- file the received and transmitted documentation.

1.2 Transparency of accounting records

Accounting transparency is grounded on the use of true, accurate and complete information which form the basis for the entries in the books of accounts. Each member of company bodies, of management or employee shall cooperate, within their own field of competence, in order to have operational events properly and timely registered in the books of accounts.

It is forbidden to behave in a way that may adversely affect transparency and traceability of the information within financial statements.

For each transaction, the proper supporting evidence has to be maintained in order to allow:

- easy and punctual accounting entries;
- identification of different levels of responsibility, as well as of task distribution and segregation;
- accurate representation of the transaction so as to avoid the probability of any material or interpretative error.

Each record shall reflect exactly what is shown by the supporting evidence. All Eni's People shall cause that the documentation can be easily traced and filed according to logical criteria.

Eni's People who become aware of any omissions, forgery, negligence in accounting or in the documents on which accounting is based, shall bring the facts to the attention of their superior, or to the body they belong to, and to the Guarantor.

2. HEALTH, SAFETY, ENVIRONMENT AND PUBLIC SAFETY PROTECTION

Eni's activities shall be carried out in compliance with applicable worker health and safety, environmental and public safety protection agreements, international standards and laws, regulations, administrative practices and national policies of the Countries where it operates.

Eni actively contributes as appropriate to the promotion of scientific and technological development aimed at protecting the environment and natural resources. The operative management of such activities shall be carried out according to advanced criteria for the protection of the environment and energy efficiency, with the aim of creating better working conditions and protecting the health and safety of employees as well as the environment.

Eni's People shall, within their areas of responsibility, actively participate in the process of risk prevention as well as environmental, public safety and health protection for themselves, their colleagues and third parties.

3. RESEARCH, INNOVATION AND INTELLECTUAL PROPERTY PROTECTION

Eni promotes research and innovation activities by management and employees, within their functions and responsibilities. Any intellectual assets generated by such activities are an important and fundamental heritage of Eni.

Research and innovation focus in particular on the promotion of products, instruments, processes and behaviours supporting energy efficiency, reduction of environmental impact, attention to health and safety of employees, of customers and of the local communities where Eni operates, and in general sustainability of business activities.

Eni's People shall actively contribute, within their functions and responsibilities, to managing intellectual property in order to allow its development, protection and enhancement.

4. CONFIDENTIALITY

4.1. Protection of business secret

Eni's activities constantly require the acquisition, storing, processing, communication and dissemination of information, documents and other data regarding negotiations, administrative proceedings, financial transactions, and know-how (contracts, deeds, reports, notes, studies, drawings, pictures, software, etc.) that may not be disclosed to the outside pursuant to contractual agreements, or whose inopportune or untimely disclosure may be detrimental to corporate interest.

Without prejudice to the transparency of the activities carried out and to the information obligations imposed by the provisions in force, Eni's People shall ensure the confidentiality required by the circumstances for each piece of news they have got to know of because of their working function.

Any information, knowledge and data acquired or processed during one's work or because of one's tasks at Eni, belong to Eni and may not be used, communicated or disclosed without specific authorization of one's superior within management in compliance with specific procedures.

4.2 Protection of privacy

Eni is committed to protecting information concerning its People and third parties, whether generated or obtained inside Eni or in the conduct of Eni's business, and to avoiding improper use of any such information.

Eni intends to guarantee that processing of personal data within its structures respects fundamental rights and freedoms, as well as the dignity of the parties concerned, as contemplated by the legal provisions in force.

Personal data must be processed in a lawful and fair way and, in any case, the data collected and stored is only that which is necessary for certain, explicit and lawful purposes. Data shall be stored for a period of time no longer than necessary for the purposes of collection.

Eni undertakes moreover to adopt suitable preventive safety measures for all databases storing and keeping personal data, in order to avoid any risks of destruction and losses or of unauthorized access or unallowed processing.

Eni's People shall:

- obtain and process only data that are necessary and adequate to the aims of their work and responsibilities;
- obtain and process such data only within specified procedures, and store said data in a way that prevents unauthorized parties from having access to it;
- represent and order data in a way ensuring that any party with access authorization may easily get an outline thereof which is as accurate, exhausting and truthful as possible;
- disclose such data pursuant to specific procedures or subject to the express authorization by their superior and, in any case, only after having checked that such data may be disclosed, also making reference to absolute or relative constraints concerning third parties bound to Eni by a relation of whatever nature and, if applicable, after having obtained their consent.

4.3 Membership in associations, participation in initiatives, events or external meetings

Membership in associations, participation in initiatives, events or external meetings is supported by Eni if compatible with the working or professional activity provided. Membership and participation considered as such are:

- membership in associations, conferences, congresses, seminars, courses;
- drawing up of articles, essays and publications in general;
- participation in public events in general.

In this regard, Eni's management and employees in charge of illustrating, or providing to the outside data or news concerning Eni's objectives, aims, results and points of view, shall not only comply with corporate procedures relating to market abuse, but also obtain the necessary authorization from their superior within management for the lines of action to follow and the texts as well as reports drawn up, such as to agree on contents with the relevant Eni Corporate structure.

IV. CODE OF ETHICS SCOPE OF APPLICATION AND REFERENCE STRUCTURES

The principles and contents of the Code apply to Eni's People and activities.

Subsidiaries listed on the Stock Exchange receive the Code and adopt it, adjusting it – where necessary – to the characteristics of their company in accordance with their management independence.

The representatives indicated by Eni in the company bodies of partially owned companies, in consortia and in joint ventures shall promote the principles and contents of the Code within their own respective areas of competence.

Directors and management must be the first to give concrete form to the principles and contents of the Code, by assuming responsibility for them both towards the inside and the outside and by enhancing trust, cohesion and a sense of team-work, as well as providing a behaviour model for their collaborators in order to have them comply with the Code and make questions and suggestions on specific provisions.

To achieve full compliance with the Code, each of Eni's People may even apply directly to the Guarantor.

1. OBLIGATION TO KNOW THE CODE AND TO REPORT ANY POSSIBLE VIOLATION THEREOF

The Code is made available to Eni's People in compliance with applicable standards, and is also available on the internet and Intranet sites of Eni spa and of subsidiaries.

Each of Eni's People is expected to know the principles and contents of the Code as well as the reference procedures governing own functions and responsibilities.

Each of Eni's People shall:

- refrain from all conduct contrary to such principles, contents and procedures;
- carefully select, as long as within their field of competence, their collaborators, and have them fully comply with the Code;
- require any third parties having relations with Eni to confirm that they know the Code;
- immediately report to their superiors or the body they belong to, and to the Guarantor, any remarks of theirs or information supplied by Stakeholders concerning a possible violation or any request to violate the Code; reports of possible violations shall be sent in compliance with conditions provided for by the specific procedures established by the Board of Statutory Auditors and by the Watch Structure of Eni spa;
- cooperate with the Guarantor and with the relevant departments according to the applicable specific procedures in ascertaining any violations;
- adopt prompt corrective measures whenever necessary, and in any case prevent any type of retaliation.

Eni's People are not allowed to conduct personal investigations, nor to exchange information, except to their superiors, or to the body that they belong to, and to the Guarantor. If, after notifying a supposed violation, any of Eni's People feels that he or she has been subject to retaliation, then he or she may directly apply to the Guarantor.

2. REFERENCE STRUCTURES AND SUPERVISION

Eni is committed to ensuring, even through the Guarantor's appointment:

- the widest dissemination of the principles and contents of the Code among Eni's People and the other Stakeholders, providing any possible instruments for understanding and clarifying the interpretation and the implementation of the Code, as well as for updating the Code as required to meet evolving civil sensibility and relevant laws;
- the execution of checks on any notice of violation of the Code principles and contents or of reference procedures; an objective evaluation of the facts and, if necessary, the adoption of appropriate sanctions; that no one may suffer any retaliation whatsoever for having provided information regarding possible violations of the Code or of reference procedures.

2.1. Guarantor of the Code of Ethics

The Code of Ethics is, among other things, a compulsory general principle of the Organizational, Management and Control Model adopted by Eni spa according to the Italian provision on the "*administrative liability of legal entities deriving from offences*" contained in Legislative Decree no. 231 of June 8, 2001.

The Watch Structure of Eni SpA also acts as Guarantor of the Code of Ethics.

The Guarantor is entrusted with the task of:

- promoting and facilitating the implementation of the Code of Ethics and the issue of reference procedures; proposing to the competent internal structures the useful initiatives for a greater dissemination and knowledge of the Code, also in order to prevent any recurrences of violations;
- promoting awareness of the Code of Ethics also through communication programs and specific training of management and employees of Eni;
- investigating reports of any violation of the Code by initiating proper inquiry procedures; taking action at the request of Eni's People in the event of receiving reports that violations of the Code have not been properly dealt with or in the event of being informed of any retaliation against Eni's People for having reported violations;
- notifying relevant structures of the results of investigations relevant to the adoption of possible penalties; informing the relevant line/area structures about the results of investigations relevant to the adoption of the necessary measures.

Moreover, the Guarantor submits to the Control and Risk Committee and to the Board of Statutory Auditors as well as to the Chairman and to the Chief Executive Officer, which report about it to the Board of Directors, a six-monthly report on the implementation and possible need for updating the Code.

In carrying out its tasks, the Guarantor avails itself of the units of the Integrated Compliance Department in charge of the activities of the technical secretariat of the Watch Structure 231 of Eni SpA.

Each information flow to the Guarantor may be sent to the following email address: organismo_di_vigilanza@eni.com.

2.2 Promotion and diffusion of the Code of Ethics

The Code is made available to Eni's People in compliance with applicable standards, and is also available on the internet and Intranet sites of Eni spa and of subsidiaries.

The Guarantor promotes the provision of every possible instrument for understanding and clarifying the interpretation and implementation of the Code.

3. CODE REVIEW

The Code review is approved by the Board of Directors of Eni spa, upon proposal of the Chief Executive Officer with the agreement of the Chairman, after hearing the opinion of the Board of Statutory Auditors.

The proposal is made taking into consideration the Stakeholders' evaluation with reference to the principles and contents of the Code, promoting active contribution and notification of possible deficiencies by Stakeholders themselves.

4. CONTRACTUAL VALUE OF THE CODE

Respect of the Code’s rules is an essential part of the contractual obligations of all Eni’s People pursuant to and in accordance with applicable law.

Any violation of the Code’s principles and contents may be considered as a violation of primary obligations under labour relations or of the rules of discipline and can entail the consequences provided for by law, including termination of the work contract and compensation for damages arising out of any violation.

EXHIBIT 12.1

Certification

I, Claudio Descalzi, certify that:

1. I have reviewed this Annual Report on Form 20-F of Eni SpA;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

Date: April 5, 2019

/s/ CLAUDIO DESCALZI

Claudio Descalzi
Title: Chief Executive Officer

EXHIBIT 12.2

Certification

I, Massimo Mondazzi certify that:

1. I have reviewed this Annual Report on Form 20-F of Eni SpA;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

Date: April 5, 2019

/s/ MASSIMO MONDAZZI

Massimo Mondazzi
Title: Chief Financial Officer

EXHIBIT 13.1

Certification Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, the undersigned officer of Eni SpA, a company incorporated under the laws of Italy (the "Company"), hereby certifies, to such officer's knowledge, that:

(i) the Annual Report on Form 20-F of the Company for the year ended December 31, 2018 (the "Report") fully complies with the requirements of section 13(a) or 15(d) as applicable, of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: April 5, 2019

/s/ CLAUDIO DESCALZI

Claudio Descalzi
Title: Chief Executive Officer

The foregoing certification is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporated by reference with any filing under the Securities Act.

EXHIBIT 13.2

Certification Pursuant to 18 U.S.C. Section 1350

For purposes of 18 U.S.C. Section 1350, the undersigned officer of Eni SpA, a company incorporated under the laws of Italy (the "Company"), hereby certifies, to such officer's knowledge, that:

(i) the Annual Report on Form 20-F of the Company for the year ended December 31, 2018 (the "Report") fully complies with the requirements of section 13(a) or 15(d) as applicable, of the Securities Exchange Act of 1934; and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: April 5, 2019

/s/ MASSIMO MONDAZZI

Massimo Mondazzi
Title: Chief Financial Officer

The foregoing certification is not deemed filed for purpose of Section 18 of the Exchange Act and not incorporated by reference with any filing under the Securities Act.

Exhibit 15(a)(i)

Eni
Remuneration Report
2019

Approved by the Board of Directors on March 14, 2019

The Report is published in the "Company/Governance" and "Publications"
sections of the Company website (www.eni.com)

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LETTER FROM THE CHAIRMAN OF THE REMUNERATION COMMITTEE

ANDREA GEMMA
Chairman of the Remuneration Committee

Dear Shareholders,
In my capacity as Chairman of the Remuneration Committee, I am very pleased to present, also on behalf of the Board, Eni's annual Remuneration Report.
In the first section, the Report describes the planned Remuneration Policy for 2019, in accordance with the Guidelines outlined for the full term.
Therefore, the Policy is in line with that of 2018 both in its structure and in the related levels of remuneration and incentives.
The Board and the Committee are convinced that the choices made reflect the Company's values, the different roles and responsibilities assigned, as well as the priorities defined in the four-year Strategic Plan.
In conducting the role, I believe it is necessary to maintain an open stance towards soliciting and acting upon shareholders' and institutional investors' feedback. To this end, ongoing market monitoring is assured throughout the Committee's annual activity cycle.
In this Report, we gave particular focus to an even more transparent and immediate representation of scenario information, the contribution of our incentive systems to the Company's strategy, the engagement process adopted and the disclosure of the specific performance results achieved.

RELATION TO THE COMPANY STRATEGY

From its previous term, the Remuneration Committee has pursued a consistent alignment between the performance targets assigned to management and the main strategic drivers of the Company. Already at the time, in fact, the metrics of the short-term and long-term incentive system had been reviewed.
Eni's Remuneration Policy has supported the process launched in 2014 for the transformation and integration of the Company, which has been strengthened operationally and financially, through the enhancement of the upstream and the restructuring of the mid-downstream in an overall context of maintaining rigorous financial discipline.
At the start of this Committee's term in 2017 we verified the consistency of the Policy set for the full term. In particular the Committee verified the new incentive systems adopted under the renewed phase of its enhanced industrial growth, driven by deeper business integration and strengthening of all corporate chain value activities, with a constant focus on efficiency and financial discipline.
The link between the short and long-term performance parameters and the main strategic drivers, focused on business integration, the decarbonisation strategy and the green business, operational and economic efficiency, and financial efficiency, is illustrated from this year in the Executive Summary of this Report. In this way, the Committee aims to represent to shareholders an even more comprehensive picture of the context in which it reaches its decisions. In addition, it is anticipating the adoption of the transparency provisions set out in Directive (EU) 2017/828, which requires an explicit indication of the link, in the remuneration policy, between the criteria of variable remuneration and the implementation of the corporate strategy in a long-term framework that ensures the Company's sustainability.

ENGAGEMENT PROCESS

Amongst the most significant activities carried out by the Committee during the year is the design and implementation of a structured Engagement Plan to reinforce the dialogue with leading institutional investors and proxy advisors. The engagement process was carried out through two cycles of meetings, in autumn and spring, with the aim of collecting feedback to enhance the planned Remuneration Policy.
I personally took part in the engagement process attending several meetings to confirm to our stakeholders the importance that Eni gives to the dialogue with the market by monitoring and evaluating its requests.
While there is a natural breadth and diversity of opinions, meetings with institutional investors representing about one-tenth of Eni's share capital have shown a substantial approval of the structure and overall balance of the Remuneration Policy defined for the current term.

In prompt response to the feedback received, the Committee nevertheless decided to make some changes to the Remuneration Report by enhancing the disclosure provided especially in the Executive Summary, supplemented with more contextual indications, and in Section II, in which the main results achieved from the implementation of the existing incentive plans are indicated.
I am of the firm opinion that the choices we made represent a significant step, in the direction identified by our investors and leading proxy advisors, for further clarity in understanding the structure and results of our Remuneration Policy.
I remain equally convinced of the need to pursue the path to improvement in order to find a balance between the legitimate expectations of management and the requests of other stakeholders. I will consequently continue to monitor the market, developments in practices and regulatory framework, guidance from our investors and policies that will need to be adopted, in compliance with the provisions of Directive (EU) 2017/828.

ACHIEVEMENTS

In line with last year, the second section of the Report shows the results achieved over a two-year time horizon (2017 and 2018) thus allowing a comparative review of the performance achieved. From this year, this review is enhanced by the specific indication of the results achieved. This is a substantial improvement in terms of transparency and completeness.
The 2018 results confirm the important achievements in relation to the Company's economic, financial and operational objectives, stemming from cost reduction measures, especially in the upstream, the optimization of margins and volumes in the mid-downstream sectors, business portfolio optimization and maintaining a rigorous financial discipline. It should be noted that given the ambitious targets set in the short-term incentive plan, the record hydrocarbon production achieved (1.85 million boe/day) is only partially reflected in the result/remunerations of the CEO and management.
Eni's ranking in environmental sustainability and protection of human capital benchmarks reflects, once again, its strategic commitment to protecting the environment and ensuring personal safety. This focus is confirmed, on the one hand, by the important results achieved in the reduction of CO_2 emissions, which dropped 6% from the 2017 level – in line with the 43% reduction target set for 2025 – and, on the other hand, by the significant penalization in the CEO and management incentive plan resulting from the occurrence of more serious incidents in 2018.
In more general terms, the Committee carefully examined the significant initiatives implemented during the year aimed at further enhancing the Company's growth prospects, contributing to the geopolitical diversification of the portfolio and to the consolidation of business opportunities in locations with strong potential in the energy sector and close to the fastest growing markets. Moreover, Eni's business activities have delivered the Company's strategic targets ahead of schedule.

CONCLUSIONS

In the future and in view of the formulation of Policy Guidelines for the new 2020-2023 term, we will continue to enhance the adoption of fair and balanced measures to adequately remunerate management and its strategic capacity through tools that, in their design and implementation, promote the creation of long-term sustainable value and safeguard the Company's assets and reputation.
The Committee will continue to ensure that the incentives remain strictly linked to the actual value created and the effective actions undertaken to successfully transform the Company in line with the objectives of the strategic guidelines, whilst considering portfolio diversification, green business and the circular economy.
Together with my fellow Directors Pietro Guindani, Alessandro Lorenzi and Diva Moriani – to whom I am personally grateful for their continuous commitment and valuable contribution to the work of the Committee – I thank you in advance and look forward to your continued endorsement of the Remuneration Policy planned for 2019.

February 26, 2019

Chairman of the Remuneration Committee

FOREWORD

This Report was approved by the Board of Directors on March 14, 2019, as per the recommendation of the Remuneration Committee, in accordance with applicable legal and regulatory requirements[1]. It defines and illustrates:

- in the first section, the 2019 Policy adopted by Eni SpA (hereafter "Eni" or the "Company") for the remuneration of Directors and Managers with strategic responsibilities[2], specifying: the general aims pursued, the bodies involved and the procedures used to adopt and implement the Policy. The general principles and guidelines outlined in this Report also apply to the remuneration policies of companies directly or indirectly controlled by Eni[3];
- in the second section, the remuneration paid in 2018 to Eni Directors, Statutory Auditors, Chief Executive Officer and General Manager and other Managers with strategic responsibilities.

The Policy described in the first section of the Report has been prepared in line with the recommendations on remuneration of the Italian Corporate Governance Code for listed companies (the "Corporate Governance Code"), in the version last approved in July 2018, which Eni adopted[4], as well as with recent recommendations by the Corporate Governance Committee[5].

The two sections of the Report are preceded by a summary ("Executive Summary") in order to provide an easily accessible overview of the key elements of the 2019 Policy, in line with the policy approved for the 2017-2020 term.

The Executive Summary also provides some additional information in order to describe the context in which remuneration choices have been made (with reference to the performance measures used to support the policies set out in the Company's Strategic Plan, performance indicators, including sustainability objectives, the results of the vote on the Remuneration Report at recent Shareholders' Meetings).

Finally, the Report lists the shareholdings held by Directors, Statutory Auditors, Chief Executive Officer and General Manager and other Managers with strategic responsibilities[6] and explains how the terms of the 2017-2019 Long-Term Monetary Incentive Plan were applied in 2018, in accordance with applicable regulation[7].

The text of this Report will be published no later than twenty-one days before the date of the 2019 Shareholders' Meeting at which investors will be invited to approve the 2018 financial statements as well as to vote on a non-binding resolution regarding the first section of this Report, in accordance with applicable regulation[8]. The text of the Report is available at the Company's registered headquarters, or on the Company website in the sections "Company/Governance" and "Publications", or via the website of the provider of disclosure and storage services for regulated information "1Info" (available at www.1info.it).

The documents relating to existing remuneration plans based on financial instruments are available in the "Company/Governance" section of the Company website.

(1) Art.123-ter of Italian Legislative Decree 58/98 (Consolidated Law on Financial Intermediation) and Art. 84-quater of the Consob Issuers Regulation (Resolution no. 11971/99 and subsequent amendments and additions).
(2) Those persons who have the power and responsibility, directly or indirectly, for planning, directing and controlling Eni fall under the definition of "managers with strategic responsibilities", in accordance with Art. 65, paragraph 1-quater of the Issuers Regulation. Eni Managers with strategic responsibilities, other than Directors and Statutory Auditors, are those who report directly to the Chief Executive Officer and to the Chairman of Eni and, in any case, those who sit on the Management Committee of the Company. For more information on the organisational structure of Eni, see the "Company" section of the Company's website (www.eni.com).
(3) The remuneration policies of the subsidiaries will be determined in respect of the principle of their management autonomy, in particular for listed companies and/or those subject to regulation, as well as in accordance with the provisions of local legislation.
(4) For further information on the terms of adoption of Eni's Corporate Governance Code, please refer to the section "Company/Governance" on the Company website.
(5) Letter of the Chairman of the Committee to the Chairmen of the boards of Italian listed companies of December 21, 2018.
(6) See Art. 84-quater, fourth paragraph, of the Consob Issuers Regulation.
(7) Art. 114-bis of the Consolidated Law on Financial Intermediation and Art. 84-bis of the Consob Issuers Regulation.
(8) Art. 123-ter of Italian Legislative Decree No. 58/98, paragraph 6.

EXECUTIVE SUMMARY

The Eni Remuneration Policy is approved by the Board of Directors, following a proposal by the Remuneration Committee, which is entirely made up of Non-Executive and Independent Directors. It is defined in accordance with the corporate governance model adopted by the Company as well as with the recommendations of the Italian Corporate Governance Code.

No changes in Remuneration Policy for 2019

The 2019 Remuneration Policy does not contain changes compared with the structure of the policy approved in 2018, in line with the policy approved for the 2017-2020 term[9], and is characterised by the adoption of a new, simpler variable incentive system, based on:

- a Short-Term Incentive Plan, featuring a three-year deferral mechanism applicable to a portion of accrued bonuses and subject to specific performance conditions over a three-year term, this is to ensure the medium-term sustainability of results achieved in the short term;
- a Long-Term Share-based Incentive Plan[10], offered to managers with the greatest influence on business performance and aimed at achieving medium-to-Long-Term objectives consistent with the Strategic Plan and the expectations of shareholders, as measured by comparison with the performance achieved by a defined Peer Group.

No change in compensation

No changes are planned in the compensation approved by the Board of Directors in 2017 for Directors with delegated powers (Chairman and Chief Executive Officer and General Manager) and for Non-Executive Directors in connection with the participation on Board committees[11], being such compensation approved for the entire term.

CONTENTS

(9) See 2017 Remuneration Report, Section I, chapter entitled Remuneration Policy Guidelines 2017 (page 15 et seq.).
(10) The conditions of the Long-Term Incentive Plan are described in the section "Remuneration Policy Guidelines 2019 – Chief Executive Officer and General Manager – Variable remuneration: Long-Term Share Incentives" of this Report, as explained in more detail in the Information Documents prepared in accordance with art. 114-bis of Consolidated Law on Financial Intermediation and art. 84-bis of the Issuers Regulation and available on the Company's website.
(11) Art. 2389, third paragraph, of the Civil Code and Art. 24 of the By-laws.

2018 Summary indicators[12]

"We worked on two fronts in 2018: the ongoing optimization of our existing portfolio of businesses and strengthening that portfolio for the future in line with the announced strategy. The results have been excellent in both cases. With regard to the existing portfolio, we doubled our operating profit and net profit while the price of brent averaged 25% higher than 2017 in euro terms. We also further strengthened our portfolio. In the Upstream segment, the establishment of Vår Energi in Norway and the building of a significant presence in the Middle East have both reinforced and geographically diversified our outlook for growth while maintaining costs low and profitability high. In Refining, with our arrival in Ruwais, we have increased our downstream capacity by 35% and taken the best opportunity for expansion in the market in terms of efficiency and profitability. This makes our overall portfolio even better balanced and more resilient against future cyclical variations".

(Claudio Descalzi)

ADJUSTED OPERATING PROFIT
11.24 billion
+ €5.44 billion compared to 2017

RECORD HYDROCARBON PRODUCTION
1.85
mln boe/day
daily production at record level

ORGANIC CASH NEUTRALITY
52 $/barrel
Organic coverage =Investments+Dividends

Adjusted profit

Adjusted operating profit of €11.24 billion and adjusted net income of €4.58 billion for the year, nearly double the performance seen in 2017.
Adjusted net cash flow: €13.9 billion (including the deferred cash in of the 2017 Zohr divestments).

Operating efficiency

Hydrocarbon production: with 1.85 million boe/day, the Upstream segment posted record highs in daily production, cash flow per barrel of $22.5, achieving a 2022 target ahead of schedule, and a reserve replacement ratio once again higher than 100%, with a three-year average of 131%.

Exploration: new discoveries in Egypt, Cyprus, Norway, Angola, Nigeria, Mexico and Indonesia; increased our portfolio of mineral interests and surpassed guidance on exploration resources adding 620 million boe of new equity resources.

Financial efficiency

Cash neutrality: organic coverage of investments and dividends at $52/barrel, an improvement over guidance ($55/barrel excluding the deferred collection of 2017 divestments).

Leverage: the Group maintains a solid financial structure with leverage at 16%, down from the 23% at December 31, 2017.

Adjusted ROACE: return on average capital employed at 8.5% (4.7% in 2017).

Sustainability, Energy Solutions and the circular economy

GHG emission intensity in the E&P sector: 21,44 tCO_2eq/thousand boe, down 20% compared with 2014 levels; in line with the announced 2025 target.

Energy Solutions, generating power from renewable sources: approximately 40 MW of installed capacity at year end and activities launched in Italy, Algeria, Kazakhstan, and Australia.

Circular economy: a number of projects launched in Italy aiming to recycling transforming and exploiting urban waste, transforming waste into next-generation fuels and other energy resources.

Dividend

Based on our performance, the Board of Directors, in its meeting of March 14, 2019, proposed the payment of a dividend of €0.83 per share, €0.42 of which was already distributed as a interim dividend in September 2018.

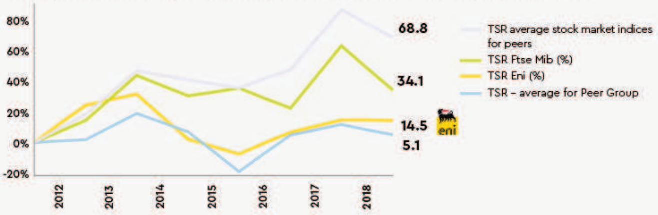
(12) These data are extracted by the Management Discussion of the Annual Report 2018. For further details see "2018 Annual Report", published together with this Report.

Other indicators

TSR

In 2012-2018, as shown in chart 1, Eni delivered a Total Shareholder Return of 14.5%, compared with 5.1 in the Peer Group[13], while the FTSE Mib index produced a TSR of 34.1% compared with an average 68.8% for the peer companies' respective benchmark Stock market indices[14].

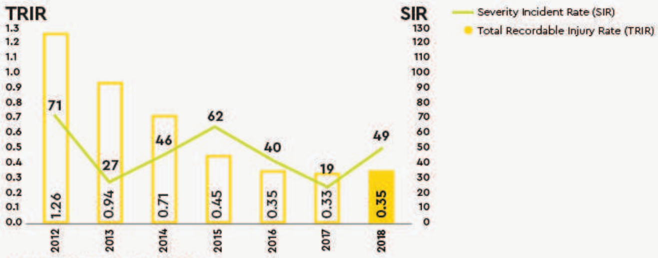
CHART 1 - TOTAL SHAREHOLDER RETURN (Eni vs. Peer Group and benchmark stock market indices)



Environmental Sustainability and Safety

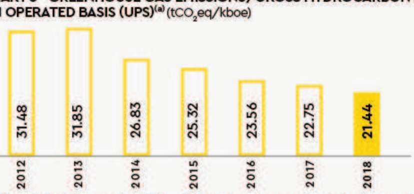
In 2018, as shown in chart 2, the Severity Incident Rate (SIR) is increased due to a number of serious incidents, whereas the Total Recordable Injury Rate (TRIR) is essentially stable at particularly low levels that are better both than the average for Oil & Gas peers (an average of 1.38 in 2017) and the second "best in class" after Eni (i.e. Chevron, which posted a TRIR of 0.65 in 2017).
In terms of GHG emission intensity in the upstream sector (where figures have been remeasured since 2014 following the addition of new emission sources), 2018 performance, as shown in chart 3, posted further improvements and remained in line with the target of a 43% reduction by 2025 compared with 2014 levels, as previously announced.

CHART 2 - TOTAL RECORDABLE INJURY RATE[(a)] AND SEVERITY INCIDENT RATE[(b)]
(employees and contractors)



(a) Injuries/hours worked x 1,000,000.
(b) Total recordable injuries weighted for severity/hours worked x 1,000,000.

CHART 3 - GREENHOUSE GAS EMISSIONS/GROSS HYDROCARBON PRODUCTION ON OPERATED BASIS (UPS)[(a)] (tCO_2eq/kboe)



(a) Since 2014 the time series of GHG emissions for upstream production has been recalculated, including new sources of methane in order to remain consistent with GHG reduction targets for 2025 compared with 2014 baseline.

(13) The Peer Group consists of ExxonMobil, Chevron, BP, Royal Duch Shell, Total, ConocoPhillips, Equinor (ex Statoil), Apache, Marathon Oil and Anadarko.
(14) Benchmark indices: Standard&Poors 500, Cac 40, FTSE 100, AEX, OBX.

Remuneration Policy

Parameters for the alignment of Remuneration Policy with the guidelines of the Strategic Plan

Remuneration policies support achievement of the guidelines set in the Company's Strategic Plan by promoting, through a balanced use of variable incentives and performance measures in the short and long-term incentive systems, the alignment of senior management's interests with the priority of creating sustainable value for shareholders over the medium to long term.
In line with the strategic drivers, these parameters are focused on the integration and expansion of all businesses, the pursuit of a clear decarbonisation strategy and the development of green business, operational and financial efficiency, while meeting the highest safety standards and the adoption of strict financial discipline.

TABLE 1 - ALIGNMENT WITH STRATEGY

STRATEGIC DRIVERS →	BUSINESS INTEGRATION		EFFICIENCY	
PERFORMANCE PARAMETERS (% WEIGHT)	EXPANSION OF ALL BUSINESSES	DECARBONIZATION AND GREEN BUSINESSES	OPERATIONAL AND FINANCIAL EFFICIENCY	FINANCIAL DISCIPLINE
STI				
Economic and financial results •EBT (12.5%) •Free Cash Flow (12.5%)	●		●	●
Operating results and sustainability of economic results •Hydrocarbon production (12.5%) •Exploration resources (12.5%)	●			
Environmental Sustainability and Human Capital •CO_2 emissions (12.5%) •Severity Incident Rate SIR (12.5%)		●	●	
Efficiency and financial strength • ROACE (12.5%) • Debt/EBITDA (12.5%)			●	●
EQUITY-BASED LTI				
Normalised TSR[a] (50%)	●	●		
NPV of proven reserves (50%)	●		●	●
↳ **GROWING VALUE AND RETURNS FOR SHAREHOLDERS** ↵				

(a) Difference between the TSR of Eni and the TSR of the benchmark stock index, adjusted for the correlation coefficient.

What we do

- Variable incentive plans anchored to predetermined, measurable, financial and non financial, targets defined in accordance with the Strategic Plan
- Pay mix of executives with a significant long-term component
- Performance assessed both in absolute terms and in comparison with industry peers
- Periods of incentive deferment and/or vesting of no less than three years and lock-up clauses for equity instruments
- Clawback in the event of error, bad faith, or serious, intentional violations of laws, regulations, or of the Code of Ethics and Company rules
- Structured engagement plan to collect the expectations and feedback of our shareholders

What we don't do

- No remuneration levels higher than national and international market references
- No forms of variable remuneration for Non-Executive Director
- No extraordinary incentives for the Chief Executive Officer or the General Manager
- No severance packages that exceed the limits set by labour agreements and applicable law
- No benefits of excessive value, other than those ones mainly limited to healthcare and pension benefits

TABLE 2 - REMUNERATION POLICY 2019 - SUMMARY

Element of pay	Purpose and conditions	Criteria and parameters	Practice/amounts	Pag. ref.
Remuneration structure and market references	*Attract, retain and motivate individuals of high managerial standard*	2019 Remuneration Policy is unchanged compared with the structure defined in 2018.	Market references CEO/GM: Peer Group Eni (*Anadarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Equinor and Total*), also used for measuring the performance of the LTI Share Plan. MSRs: Roles of the same level of managerial complexity and responsibility in industrial corporations in national and international markets.	21 22
Fixed Remuneration	*Reward the resposibilities held, skills and experience*	Chief Executive Officer and General Manager (CEO/GM): Fixed remuneration is set in relation to the delegated powers assigned over the term and positions held as General Manager. Managers with strategic responsibilities (MSRs): Fixed pay is based on the role assigned, potentially adjusted to median market remuneration level.	CEO/GM: Fixed remuneration equal to €1,600,000, of which: - CEO: €600,000. - GM: €1,000,000.	23 30
Short-Term Incentive Plan	*Motivate managers to achieve annual budget targets in a perspective of medium/ long-term sustainability* (Plans subject to clawback mechanism)	2019 targets for CEO/GM: *1. Economic and financial results: EBT (12.5%) and Free cash flow (12.5%)* *2. Operating results and sustainability of economic results: hydrocarbon production (12.5%) and exploration resources (12.5%)* *3. Environmental sustainability and human capital: CO_2 emission (12.5%) and Severity Incident Rate (12.5%)* *4. Efficiency and financial strength: ROACE (12.5%) e Debt/EBITDA (12.5%)* 2019 targets for MSRs: Business and individual targets set on the basis of those assigned to the CEO/GM and the responsibilities assigned to them. Assessment - performance scale: 70 ÷ 150 points (target= 100) - below 70 points the performance is considered to be equal to zero - the minimum incentive threshold is equal to overall performance of 85 points - 1.1 multiplier applicable to overall performance score in case of out-of-budget development initiatives of stategic importance, within the limit of 150 points. Incentive opportunity - Incentive base: defined as a percentage of fixed remuneration, and differs depending on the level of assigned role. - Incentive vested: between 85% and 150% of incentive base, made up of a *portion paid annually (65%) and a deferred portion (35%)* determined as a function of the average of Eni annual performance results over the three-year deferral period, between 28% and 230% of the awarded deferred portion.	CEO/GM - Incentive base: 150% of fixed rem. - Payable annual portion: - Threshold 83% of fixed rem - Target 98% of fixed rem - Max 146% of fixed rem. - Payable deferred portion: - Threshold 38% of fixed rem - Target 68% of fixed rem - Max 181% of fixed rem. MSRs - Incentive base: up to 100% of fixed remuneration. - Payable annual portion: up to 98% of fixed remuneration. - Payable deferred portion: up to 121% of fixed remuneration.	23-26 30
2017-2019 Long-Term Equity-based Incentive Plan	*Promote sustainability and long-term value creation for shareholders* (Plans subject to clawback mechanism)	Performance parameters - Difference between the TSR[1] of Eni and the TSR of the reference stock index, adjusted for the correlation coefficient (50%); - Net Present Value of proven reserves [2] (50%). Performance measurement over a 3-year period Performance is measured in relative terms compared with the companies in the peer group in line with the following incentive scale: 1st Place 180%; 2nd Place 160%; 3rd Place 140%; 4th Place 120%; 5th Place 100%; 6th Place 80% (median performance level); 7th-11th Place 0%. Number of shares awarded Determined by the ratio between the monetary value (calculated as a % of fixed remuneration differentiated according to the level of the role), and the price of the award, calculated as the average of the daily prices recorded in the four months before the month in which the Board approves the award. Number of shares granted at the end of the vesting period Determined on the basis of performance over 3 years applying a variable multiplier between 26.6% (*threshold*) and 180% of the number of awarded shares. Restriction period For senior managers still in service (including GM and MSRs), 50% of the shares granted at the end of the vesting period are to remain restricted for one year from the granting date.	CEO/GM - Value of awarded shares: 150% of total fixed remuneration. - Value of granted shares : between 40% and 270% of fixed remuneration. MSRs - Value of awarded shares: depending on the level of the role, up to 75% of fixed remuneration. - Value of shares granted: depending on the level of the role, up to 135% of fixed remuneration. *N.B.: the monetary values are net of the impact of any changes in the stock price.*	26-28 30
Non-monetary benefits	*Promote managers retention*	Benefits, mainly insurance and welfare related, defined in national collective bargaining and in supplementary Company-level agreements (including GM and MSRs).	- Supplementary pension scheme - Supplementary healthcare scheme - Insurance - Company car for business and personal use	28 30
Payments due in the event of termination of office or employment	*Protect the Company from potential litigation and/ or competitive risks associated with terminations without just cause*	Payments due in the event of termination of office or employment CEO - administrative office (CEO) – an indemnity in the event of non-renewal of the office or early termination without just cause, as well as resignation prior to the expiry of the term justified by a reduction of delegated powers; - executive employment relationship (including the position as GM) – an indemnity in the event of consensual termination set in accordance with the Company parameters and policy, within the limits of the protections laid down by national collective bargaining agreement for senior managers. Indemnities are not due in the event of dismissal for «just cause» and resignation not justified by a reduction of delegated powers. Non-competition agreement CEO/GM Payment based on current remuneration levels and the extension of period and commitments undertaken: - validity: 12 months post termination; - restricted markets: Exploration & Production and Midstream; - restricted nations: 18 countries (*Algeria, Angola, Congo, Egypt, Ghana, Indonesia, Iraq, Italy, Kazakhstan, Libya, Mexico, Mozambique, Nigeria, Norway, Russia, UK, USA, Venezuela*); - confidentiality and non-solicit restrictions. Non-competition agreement MSRs Only for cases of termination presenting high-competitive risks relating to the nature of the position; payment based on current remuneration levels and the extension of period and commitments undertaken.	Indemnities for CEO/GM - Administrative office: (CEO): 2 years of fixed rem., for a total of €1,200,000, in accordance with EC Recommendation no. 385/2009 - Executive employment relationship (GM): 2 years of fixed remuneration and short term incentive, within the limits of protections provided for in national collective bargaining agreement Payment for the non-competition agreement of CEO/GM: - A fixed component of €1,800,000; - A variable component to be determined in line with average annual performance over the previous three years: - Zero for performance below target - €500,000 for performance on target - €1,000,000 for maximum performance.	28-29 31

(1) Total Shareholder Return measures the overall performance of a share, taking into account both price developments and distributed and reinvested dividends, over a specified period.
(2) Net Present Value of proven reserves is the present value of future cash flows generated by proven reserves net of future production and development costs, and taxes. It is calculated against a reference base defined by the Securities Exchange Commission on the basis of data published by oil companies in their official filings (Form 10-K and Form 20-F).

CEO/GM Remuneration for the 2017-2020 term

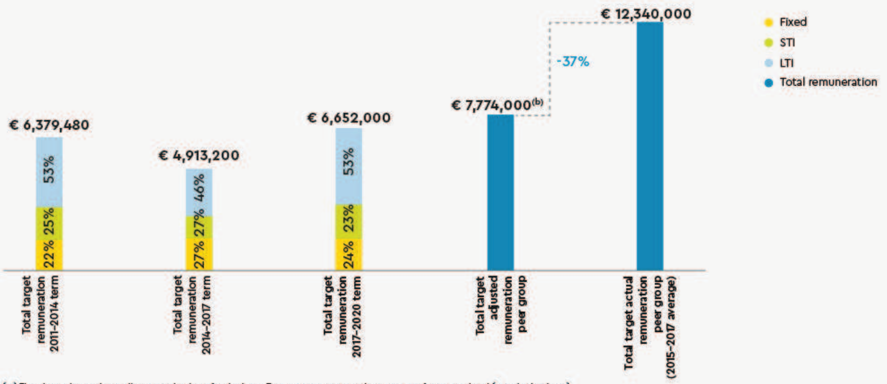
Pay Mix focused on long-term components

Total remuneration for Eni's Chief Executive Officer and General Manager for the 2017-2020 term was set taking account of the termination of the restrictions on reducing remuneration applied for the 2014-2017 term (-25% on the maximum potential financial benefit) and working to balance the pay mix with a greater focus on long-term variable components (53% vs. 46%).

Median remuneration of Peer Group adjusted for differences with Eni capitalisation

Chart 4 shows the value of the remuneration package for Eni's Chief Executive Officer and General Manager for the 2017-2020 term compared with the two previous terms. The total target remuneration for the 2017-2020 term was also verified against the total target remuneration of the Peer Group for the period 2015-2017, reduced by 37% (€7,774 thousand) in order to take account of the difference in capitalisation compared with Eni.

CHART 4 – REMUNERATION PACKAGE AND CEO/GM PAY MIX - TARGET[a]



(a) The chart shows the undiscounted values for the Long-Term components at the target performance level (nominal values).
(b) Adjusted for percentage difference between Eni capitalisation and Peer Group median capitalisation (-37%).

Characteristics of Peer Group

Table 3 reports the composition of the Peer Group, including Eni's leading Oil & Gas competitors operating mainly in the Upstream sector, given the greater weight of that sector in Eni's operations, and the size characteristics, which show an average capitalisation that is about 37% greater than Eni's.

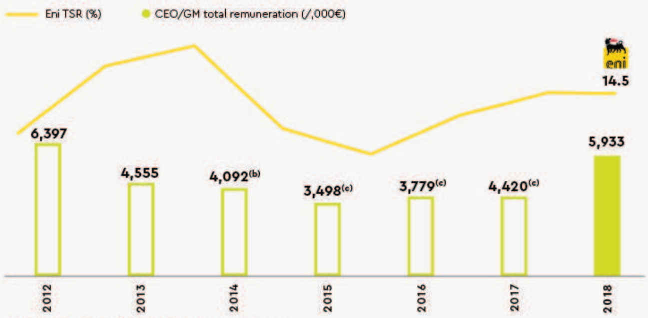
TABLE 3 - PEER GROUP

	Company	Average capitalisation in 2015-2017 [Bln €]	2017 Production [Mn boed]	2017 Reserves [Bln BOE]	Peer Compensation	Peer Performance
1.	Exxon Mobil	317	4.1	21.2	√	√
2.	Royal Dutch Shell	194	3.8	12.2	√	√
3.	Chevron	188	2.7	11.7	√	√
4.	Total	112	2.6	11.5	√	√
5.	BP	109	3.7	18.4	√	√
6.	ConocoPhillips	56	1.4	5.0	√	√
7.	Equinor	52	1.9	5.4	√	√
8.	Anadarko	28	0.7	1.4	√	√
9.	Apache	17	0.5	1.2	√	√
10.	Marathon Oil	11	0.4	1.4	√	√
	Mediana Peer Group	82	2.3	8.4		
	Eni	**52**	**1.8**	**7.0**		
	Δ% Eni vs Peer Group	*-37%*	*-20%*	*-17%*		

Chart 5 compares developments in Eni TSR and total CEO/GM remuneration for 2012-2018.

Alignment with performance

CHART 5 - PAY FOR PERFORMANCE ANALYSIS
(Eni TSR vs CEO/GM total remuneration for 2012-2018)[a]



(a) Data from Table 1 of 2012-2018 Eni Remuneration report.
(b) For 2014 fixed remuneration is calculated as the sum of pro-rata amounts paid to the outgoing CEO and to incoming CEO.
(c) For 2015, 2016 and 2017, total remuneration also includes incentives accrued by the current CEO/GM in his previous role as GM of the E&P Division.

Results of shareholders' vote on Eni Remuneration Policy

The Shareholders' Meeting of May 10, 2018, in accordance with the provisions of the applicable legislation (Art. 123-ter, paragraph 6, of Legislative Decree No. 58/98), issued an advisory vote on the first section of the 2018 Remuneration Report.
The overall percentage of participants voting in favour in 2018 was 80.46% while the subset of institutional investors voting in favour came to 64.23%, with an average of approval rate, in the last five years of about 90%.

CHART 6 - RESULTS OF THE SHAREHOLDERS' MEETING VOTES ON THE 2014-2018 ENI REMUNERATION REPORT

Average approval rate of about 92.8%

Average approval rate of about 86.2%

SECTION I - REMUNERATION POLICY 2019

Corporate governance

BODIES AND PARTIES INVOLVED

Compliance of Policy with provisions of law and By-laws

The Policy governing the remuneration of members of the Eni Board of Directors is defined in accordance with the provisions of law and the By-laws, according to which:

- the Shareholders' Meeting determines the remuneration of the Chairman and other members of the Board of Directors, at the time they are appointed and for the entire duration of their term;
- the Board of Directors determines the remuneration of the Directors with delegated powers and of those who participate in Board Committees, after examining the opinion of the Board of Statutory Auditors.

In line with Eni's corporate governance system[15], the Board is responsible for:

- defining the Company's targets and approving the Company's performance thereby determining the variable remuneration of eligible Directors;
- approving the general criteria for remunerating Managers with strategic responsibilities;
- subject to a proposal of the Chairman in agreement with the Chief Executive Officer, defining the remuneration structure of the Group Head of Internal Audit in accordance with the remuneration policies of the Company, on receipt of a favourable opinion from the Control and Risk Committee and having examined the opinion of the Board of Statutory Auditors.

In line with the recommendations of the Italian Corporate Governance Code, the Board of Directors is supported by a Committee of independent Non-Executive Directors (the Remuneration Committee), which makes proposals and provides advice on remuneration issues.

ENI REMUNERATION COMMITTEE

COMPOSITION, APPOINTMENTS AND TASKS

The Committee is composed of four Non-Executive and Indipendent Directors

The Eni Remuneration Committee was first established by the Board of Directors in 1996. Its composition and appointment, remit and terms of reference are governed by specific rules approved by the Board of Directors and published on the Company website[16].

The Committee may be composed of three to four Non-Executive Directors, all of whom meet the definition of independence as set out in Italian law and the Italian Corporate Governance Code. According to the Committee's rules, the Committee may be composed of Non-Executive Directors, a majority of whom shall be independent, provided that in this case the Chairman is chosen from among the independent Directors. The Committee's rules also require that at least one of its members possess adequate knowledge and experience of financial matters or remuneration policies, as assessed by the Board at the time of his or her appointment (art. 6.P.3).

Below are details of the composition and meetings of Committee in 2018.

CHART 7 - COMPOSITION OF THE COMMITTEE[(a)]

Andrea Gemma (Chairman)
Pietro A. Guindani[(b)]
Alessandro Lorenzi[(b)]
Diva Moriani

8 meetings in 2018
Average duration:
2h and 30 minutes

(a) Composition following renewal of corporate bodies (Board of Directors' decision on April 13, 2017 as announced in the press release of the same date). The Committee is entirely composed of Non-Executive and Independent Directors, pursuant to law and Corporate Governance Code.
(b) Directors Guindani and Lorenzi have been appointed from the minority slate.

(15) For more information regarding the Eni corporate governance system, please refer to the "Corporate Governance Report" published in the "Company/Governance" section of the Company website.
(16) The rules of the Remuneration Committee are available in the "Company/Governance" section of the Company's website.

The Chief Services & Stakeholder Relations Officer di Eni or, on his behalf, the Executive Vice President Compensation & Benefits, acts as Secretary to the Committee. The Secretary assists the Committee and its Chairman in carrying out the associated activities, with the support of the competent Compensation & Benefit units.

Consultative and advisory functions of the Remuneration Committee

In line with the recommendations of the Italian Corporate Governance Code (Art. 6.P.4 and Art. 6.C.5), the Committee performs the following consultative and advisory functions for the Board of Directors:
- submits the Remuneration Report and in particular the Remuneration Policy for Directors and Managers with strategic responsibilities to the Board of Directors for approval, prior to its presentation at the Shareholders' Meeting called to approve the annual financial statements, in accordance with the time limits set by applicable law;
- periodically evaluates the adequacy, overall consistency and actual implementation of the adopted Policy, formulating proposals as appropriate for approval by the Board of Directors;
- presents proposals for the remuneration of the Chairman and the Chief Executive Officer, covering the various forms of compensation and benefits envisaged;
- presents proposals for the remuneration of members of the Board's internal committees;
- having examined the Chief Executive Officer's input, proposes general criteria for the compensation of Managers with strategic responsibilities, the annual and Long-Term incentive plans, including equity-based plans, for establishing performance targets and assessing results for performance plans in connection with the determination of the variable portion of the remuneration for Directors with delegated powers and with the implementation of incentive plans;
- monitors the execution of Board resolutions;
- reports at the first available meeting of the Board of Directors through the Committee Chairman on the most significant matters examined by the Committee during the meetings. It also reports to the Board on its activities at least every six months and no later than the time limit for the approval of the Annual Report and of the Interim Report at June 30, at the Board meeting designated by the Chairman of the Board of Directors.

Furthermore, in exercising its functions, the Committee may express opinions as required by Company procedures in relation to transactions with related parties, within the terms specified therein.

OPERATING PROCEDURES

According to its Rules, the Committee meets as often as necessary to fulfil its functions, usually on the dates established in the annual meeting schedule approved by the Committee itself, and in the presence of at least the majority of its current members. The Chairman of the Committee calls and chairs the meetings; in case of absence or impediment, the meeting is chaired by the oldest attending member. The Committee decides with an absolute majority of those present; in the case of tied votes, the Committee Chairman has a casting vote. The Committee Secretary, who may be assisted in this function by the Executive Vice President Compensation & Benefits, produces the minutes of the meetings.

Minuting of meetings and participation of Statutory Auditors in Committee meetings

The Chairman of the Board of Statutory Auditors (or another Statutory Auditor appointed by said Chairman) may attend the meetings of the Committee; other Statutory Auditors may also participate. Meetings may be attended, at the invitation of the Chairman of the Committee acting on behalf of the Committee, by the Chairman of the Board of Directors and the Chief Executive Officer; the meetings may also be attended by Managers of the Company or other persons, including other members of the Board of Directors, to provide information and feedback on individual agenda items.

No Director and in particular no Director with delegated powers may participate in Committee meetings in which proposals are submitted to the Board relating to his or her own personal remuneration (art. 6.C.6), except where the proposals regard all members of the Committees within the Board of Directors. The provisions applicable to the composition of the Committee shall remain applicable where the Committee is called upon to perform the duties required under the procedure for related-party transactions adopted by the Company.

May engage external independent consultants

The Committee has the right to access information and Company managers as necessary to perform its duties, and to make use of external consultants, whose independence is assured, within the terms and limits of the budget set by the Board of Directors (art.4.C.1, letter e; art. 6.C.7).

The Committee, through its Chairman, shall report to the Board of Directors on the results of its meetings at each subsequent full Board meeting, in addition to providing half-yearly updates on the manner in which it has exercised its duties and the issues it has addressed (art.4.C.1, letter d).

Meetings held in 2018

ACTIVITIES PERFORMED IN 2018 AND PLANNED FOR 2019

In 2018, the Remuneration Committee met 8 times, with an average attendance of 100% of its members and an average duration of 2 hours and 30 minutes.
At least one member of the Board of Statutory Auditors participated in each meeting, with the constant participation of the Chairman of the Board of Statutory Auditors, as well.
At the invitation of the Chairman of the Committee, Managers of the Company and advisors

1ST QUARTER — JANUARY - MARCH

GOVERNANCE
- Definition of Remuneration Policy Guidelines.
- Preparation of Remuneration Report.

COMPENSATION
- Periodic assessment of the policy adopted in the previous year and of remuneration comparative studies.
- Definition of the targets related to the variable incentive plans.
- Verification of results related to the Short-Term Incentive Plan.
- Implementation of the Short-Term Incentive Plan.

ENGAGEMENT
- Assessment of the outcomes of engagement activities with leading institutional investors and proxy advisors.

2ND QUARTER — APRIL - JUNE

GOVERNANCE
- Presentation of the Remuneration Report to the Shareholders' General Meeting.

COMPENSATION
- Verification of results related to the Long-Term incentive Plan LTI.

ENGAGEMENT
- 2nd round of meetings with leading institutional investors and proxy advisors.
- Assessment of the outcomes of engagement activities with leading institutional investors and proxy advisors.

Governance

In the first part of 2018, in implementation of the recommendations of the Italian Corporate Governance Code, the Committee conducted its ongoing review of Remuneration Policy, as implemented in 2017, also with a view to developing new Policy proposals for 2018, electing to maintain the structure and the remuneration criteria for Directors and Managers with strategic responsibilities established in 2017 for the entire term, with special regard to the introduction of a new and generally simplified variable incentive system, as discussed in greater detail in the 2017 Remuneration Report[17].
The Committee then analysed Eni's 2018 Remuneration Report for the purpose of subsequent approval by the Board and presentation to the shareholders and, in a dedicated session, examined the results of the 2018 Shareholders' Meeting as compared with the results of the leading Italian and European corporations and with those of the companies within the relevant Peer Group.
In the autumn of 2018, the Committee periodically monitored developments in the legislative framework and market standards concerning the reporting of remuneration-related information, with a specific focus, for 2019, on the content of Directive (EU) 2017/828 (the Shareholder Rights Directive, or "SHRD II"), including for the purpose of establishing the guidelines for preparing this Report. During the current year, in addition to the ordinary activities set for its annual cycle, the Committee will continue the work that began in 2018 to study the content and implementing measures of SHRD II, with a particular emphasis on its impact on the process of defining, revising and implementing remuneration policies and on the adoption of related reporting standards[18], including in order to verify the need to implement any internal regulations or procedures.
The Committee will also begin ordinary review activities related to the end of the term in the spring of 2020.

Compensation

With regard to issues concerning the implementation of remuneration policies in the light of the criteria approved for the entire term, in 2018 the Committee performed the following activities:
- verification of the company's 2017 results for the purpose of implementing the Short-and Long-Term variable incentive plans, using a predetermined gap analysis method approved by the Committee in order to neutralise the positive of negative impact of exogenous factors and enable the objective assessment of the performance achieved;

(17) 2017 Remuneration Report, Executive Summary (p. 6) and Section I, 2017 Remuneration Policy Guidelines, (pp. 15 and ff.).
(18) With regard to the guidance that the European Commission is required to issue, in implementation of Article 9c, paragraph 6, of the SHRD II Directive to ensure the harmonisation of provisions concerning remuneration reports and the standardised presentation of information.

participated in specific meetings to provide information and clarifications requested by the Committee to pursue the analysis conducted.
The Committee scheduled eight meetings for 2019, four of which had already been held as of the date of approval of this Report.
The main activities pursued by the Committee in the year are shown below, with an indication of the main initiatives planned for this year, in line with its annual activity plan.

Meetings planned in 2019

3RD QUARTER — JULY – SEPTEMBER

GOVERNANCE
- Benchmark analysis of the results of the vote of the Shareholders' Meeting on proposed Remuneration Policy.

4TH QUARTER — OCTOBER - DECEMBER

GOVERNANCE
- Monitoring of the regulatory framework and of the voting policies of leading institutional investors and proxy advisors.

ENGAGEMENT
- Approval of the annual engagement plan.
- 1st round of meetings with leading institutional investors and proxy advisors.

COMPENSATION
- Implementation of the Long-Term Incentive Plan (LTI).

- definition of 2018 performance targets relevant to the variable incentive plans;
- definition of proposals for the implementation of the Deferred Monetary Incentive Plan for the Chief Executive Officer and General Manager;
- finalising the proposal (2018 award) for the implementation of the Long-Term Share Incentive Plan 2017-2019 for the Chief Executive Officer and General Manager and for the senior managers deemed critical for the business.

During this year, in addition to the usual activities provided for in its annual plan, the Committee will also begin analysis to prepare remuneration policies for the 2020-2023 Board term.

Engagement

As part of its ongoing monitoring of the positions of institutional investors and leading proxy advisors on remuneration issues, during 2018, the Committee performed the following activities:
- review of the outcome of the meetings conducted with main institutional investors and proxy advisors, before the 2018 Shareholders' Meeting, in order to maximize shareholder consensus on the 2018 Remuneration Policy. These meetings were also attended by the Chairman of the Committee, underscoring the importance the Committee attributes to shareholder dialogue;
- risk and scenario assessment activities, as well as voting projections, which were performed with the supporting of a leading consulting firm;
- examination of voting recommendations issued by leading proxy advisors and, in response to a number of issues that emerged, start of further extensive dialogue with investors, sending a letter clarifying the reasons and rationale of the choices made.

In the second half of the year, the Committee examined the general criteria for defining the 2019 engagement plan by conducting a preliminary analysis and segmentation of the institutional investors that attended the 2018 Shareholders' Meeting, while taking account, for the purpose of setting targets, of parameters related to the materiality of the interest held in the Company and the vote expressed at the most recent meetings.
The Committee also assessed the advisability of keeping an open channel of communication with the main proxy advisors given the role they play and their significant influence on how investors vote, particularly as concerns those who have highly diversified portfolios with numerous foreign investments, in accordance with the indications of the recent SHRD II Directive.
During the current year, the Committee will move ahead with the implementation of the 2019 plan by conducting a second cycle of meetings, following the meeting held in the autumn of 2018, with the goal of promoting investor participation and engagement in the Shareholder Meeting scheduled for May 14 based on an increasingly broad understanding of the principles, criteria and mechanisms of Remuneration Policy planned for the current term and in light of the results achieved and the remuneration paid in 2018.

2019 REMUNERATION POLICY APPROVAL PROCESS

Policy consistent with recommendations of Italian Corporate Governance Code

In performing its duties, the Remuneration Committee focused on defining the structure and contents of the Remuneration Policy, for the purposes of preparing this Report, specifically at meetings held on November 8, 2018, January 23, February 12 and 26, 2019, in accordance with the recommendations of the Italian Corporate Governance Code. In taking its decisions, the Committee reviewed the appropriateness, overall consistency and effective implementation of the Policy Guidelines approved for 2018.

In preparing this Report, it also considered national and international disclosure standards for the preparation of the Remuneration report, as well as feedback received during meetings with leading international investors and proxy advisor.

The Committee also considered comparative remuneration studies prepared by independent international consultants (Mercer, Willis Towers Watson e Korn Ferry-Hay Group), in the preliminary analysis for the 2019 Remuneration Policy proposals.

The 2019 Eni Remuneration Policy for Directors and other Managers with strategic responsibilities was approved by the Board of Directors, upon proposal of the Remuneration Committee, at its meeting on March 14, 2019, alongside approval of this Report. Once approved, policies are implemented by management in accordance with instructions from the Board of Directors and with the assistance from relevant Company departments.

ENGAGEMENT ON REMUNERATION POLICY

Adoption of comprehensive engagement strategy
- **periodic cycles of meetings**
- **Shareholders' Meeting events**
- **ongoing updating of information available on the website**

At Eni, we develop interaction with our shareholders and institutional investors regarding remuneration policies by way of a number of communication channels, including: the organization of period meetings and conference calls, the meeting of shareholders as a concluding verification of past interactions, and the provision of thorough, detailed information on our website.

This dialogue with our most significant institutional investors and main proxy advisors is ensured, first and foremost, by defining a detailed engagement plan, which is implemented annually by the Compensation & Benefits and Investor Relations functions in support of the policy proposals to be submitted for approval by the Shareholders' Meeting.

The Committee is kept constantly informed of activities aimed at defining and implementing the annual engagement plan. The outcome of meetings is monitored, and the feedback received is analysed in order to provide clarification and verify the resolution of any potentially critical issues. The Chairman of the Committee, in coordination with the Chairman of the Board of Directors, may attend the meetings in order to underscore the importance of direct communication with the market in relation to issues relevant to the Committee.

In compliance with the Italian Corporate Governance Code (Article 6 – Comments), the Committee also reports on its procedures at the annual Shareholders' Meeting by way of the Committee Chairman or other duly appointed member.

Feedback received in 2018 actions planned for 2019

In 2018, in response to shareholders vote, the Committee deemed it to be appropriate to intensify dialogue with institutional investors and the proxy advisors in order to enhance understanding of the reasoning behind decisions made for the full term, with a particular focus on definition of the base salary for the Chief Executive Officer and General Manager and on certain specific characteristics of the new incentive system.

Based on the observations and feedback received during the meetings held with a significant core group of institutional investors (representing a total of over 10% of share capital), including with regard to the need to ensure greater transparency into current practice, the Committee decided to propose certain changes to this Report to describe, in the Summary, the connection between the Remuneration Policy for management and Company strategies and to reinforce the disclosures in Section II of the report concerning implementation of the short and long-term incentive plans in relation to the results actually achieved and the related payout levels.

CHART 8 – ANNUAL ENGAGEMENT PLAN

Engagement

SEPTEMBER - DECEMBER	JANUARY - APRIL	MAY - JULY
• Definition of annual Engagement Plan • 1st round of meetings with leading institutional investors and proxy advisors • Monitoring and scenario analysis (regulatory framework, voting policies, best practices) • Assessment of the outcomes of engagement activities	• 2nd round of meetings with leading institutional investors and proxy advisors • Assessment of the outcomes of engagement activities • Examination of voting recommendations of proxy advisors • Voting projections	• Shareholders' Meeting: presentation of planned Remuneration Policy • Benchmark analysis of the results of the vote of the Shareholders' Meeting, with focus on position of institutional investors

Full information regarding remuneration of Directors and management is regularly updated and made available under the "Remuneration[19] heading" of the "Company/Governance" section of the Company website.

Purpose and general principles of the Remuneration Policy

PURPOSE

Consistent with the governance model and recommendations of the Italian Corporate Governance Code

The Eni Remuneration Policy is defined in accordance with the governance model adopted by the Company and with the recommendations of the Italian Corporate Governance Code (referred to below in the main implementation principles and criteria).
The remuneration of Directors and Managers with strategic responsibilities is established in order to attract, motivate and retain individuals of high professional and managerial standing (Art. 6.P.1).
It is also aimed at ensuring the alignment of management interests with the primary goal of creating value for shareholders over the medium to long term (Art. 6.P.2).
Eni's Remuneration Policy contributes to achieving the Company's mission and strategies, by:

- promoting actions and behaviours reflecting the Company's values and culture, consistent with the principles of plurality, equal opportunity, enhancement of individuals' knowledge and skills, non-discrimination, fairness and integrity, as described in the Code of Ethics[20] and Eni Policy "Our people"[21];
- recognising roles and responsibilities assigned, results, and the quality of professional contribution, taking into account the operating environment and relevant market references;
- defining incentive structures that are tied to the sustainable long-term achievement of financial, business development, operational and individual objectives, consistent with the Company's Strategic Plan and the responsibilities assigned.

Goals
- **promoting Company's values**
- **recognising roles, responsibilities and results**
- **defining sustainable incentives in the long term consistent with the Strategic Plan**

GENERAL PRINCIPLES

In pursuing the above, the remuneration of Directors and Managers with strategic responsibilities is defined in line with the following principles and criteria:

REMUNERATION OF NON-EXECUTIVE DIRECTORS

No variable remuneration for Non-Executive Directors

Remuneration of Non-Executive Directors is commensurate with the effort required for participation on Board Committees set up in accordance with the Articles of Association (Art. 6.P.2); appropriate differentiation between the remuneration afforded to Committee Chairmen, and that of other Committee Members, considering the different roles respectively held regarding coordination of work and relationships with Corporate bodies and managerial teams; Non-Executive Directors are not beneficiaries of variable incentive plans, including equity-based ones, unless decided otherwise by the Shareholders' Meeting (Art. 6.C.4).

(19) https://www.eni.com/en_IT/company/governance/remuneration.page
(20) For more information, please refer to the "2018 Corporate Governance Report" published in the "Company/Governance" section of the Company website.
(21) Policy approved by the Board of Directors on July 28, 2010.

STRUCTURE OF EXECUTIVE REMUNERATION

The remuneration package is appropriately balanced between a fixed and a variable component, in relation to the strategic objectives and the risk management policy of the Company, taking due account of its business sector (Art. 6.C.1.a).

Vesting and/or deferral periods of at least three years

Executive roles with the greatest influence on business performance are characterized by variable remuneration containing a significant percentage of incentive components, particularly of long-term (Art. 6.P.2). The vesting period and/or incentive deferral period are defined over a period of at least three years, in line with the long-term nature of the business activities performed and with the associated risk profile (Art. 6.C.1.e).

MARKET REFERENCES

Total remuneration tied to applicable market references

Total remuneration packages aim for consistency with market references applicable for positions or roles of similar level of responsibility and complexity, based on panels of relevant comparators that were developed through benchmarking analysis carried out by international remuneration advisors.

FIXED REMUNERATION

The fixed component is consistent with role and/or responsibilities, as well as adequate in the event of non-payment of the variable component (Art. 6.C.1.c).

VARIABLE REMUNERATION

The variable component is defined within maximum limits (Art. 6.C.1.b), and is aimed at aligning remuneration with performance actually achieved.

INCENTIVE TARGETS AND SUSTAINABILITY OF RESULTS

Financial and non-financial targets related to short-and long-term variable remuneration, including equity-based compensation, are defined in a manner consistent with the four-year Strategic Plan and with the expectations of shareholders, in order to foster a strong results-oriented focus and meld operational and financial soundness with social and environmental sustainability.

Assessment of long-term performance against performance of peers

Targets are defined in advance, measurable and mutually complementary in order to fully capture the priorities that underpin the Company's overall performance (art.6.C.1 letter d). These targets are defined so as to ensure:

- annual performance assessment, on the basis of a balanced scorecard that values the overall business and individual performance, defined in relation to targets specific to each area of responsibility, and for those in charge of internal audit responsibilities, in line with their specific assigned role (Art. 6.C.3);
- the definition of long-term incentive plans that allow Company performance to be evaluated both in absolute terms, i.e. based on the capacity to generate sustained growth in profitability, and in relative terms compared with a Peer Group, by way of a ranking against Eni's main international competitors.

EQUITY-BASED COMPENSATION PLANS

Equity-based compensation plans are designed to ensure alignment with shareholders expectations over the medium to long term, by way of: three-year vesting periods, linkage with pre-determined and measurable performance targets, the provision of a withholding period that applies to a proportion of share awards (Art. 6.C.2).

VERIFICATION OF RESULTS

Incentive awards linked to variable remuneration are made pursuant to a detailed verification process that assesses performance against assigned targets, net of the effects of exogenous variables[22], on the basis of a variance analysis methodology approved by the Committee, in order to recognise actual value-added attributable to managerial actions.

(22) Exogenous variables are those events that, due to their nature or though Company choice, are not under the control of the managers, such as, for example, Oil & Gas prices or the euro/dollar exchange rate.

CLAWBACK CLAUSES

The adoption, with specific rules approved by the Board of Directors, acting on a proposal of the Remuneration Committee, of a mechanism that provides for the variable component of remuneration, if already paid and/or granted, to be recouped, and if still subject to deferral, to be withheld, in instances where such incentives results were based on data that subsequently proved to be manifestly misstated (Art. 6.C.1.f).
Beneficiaries must also make restitution of all incentives for the year (or years) for which they have been found responsible for:
- the fraudolent alteration of the data used in verifying performance for the purpose of entitlement to the incentive;
- and/or the commission of serious and intentional violations of law and/or regulations, the Code of Ethics or Company rules that are pertinent to or have an impact on the employment relationship, affecting the associated fiduciary relationship, without prejudice to any action allowed under law for the protection of the Company's interests.

The Clawback Policy provides that the activation of recoupment claims (or withdrawal of incentives awarded but not yet paid) must take place, once appropriate verification has been completed, within three years of payment (or award) in cases of error, and within five years in cases of fraud.

Clawback clauses triggered in the following cases:
- **manifestly misstated data**
- **fraudolent alteration of data**
- **serious and intentional violations of law and/or regulations, the Code of Ethics or Company rules**

NON-MONETARY BENEFITS

Non-monetary benefits are determined in line with relevant market comparators, consistent with local regulation, in order to complete and enhance the overall remuneration package, taking account of the roles and/or responsibilities, and allowing for relevant social security and insurance components.

Pension and social security benefits

SEVERANCE INDEMNITIES AND NON-COMPETITION AGREEMENTS

To the extent that additional payments may be recognized upon termination of employment and/or term of office for executive roles, and that non-compete agreements may apply for roles at greater risk of "poaching", these are defined in terms of either a maximum amount or number of years of remuneration, in line with the remuneration received and the performance achieved, as per recommendations set forth in the implementation criteria (Art. 6.C.1.g) of the Italian Corporate Governance Code.

Severance indemnities and non-compete agreements consistent with remuneration received and results achieved

Remuneration Policy Guidelines 2019

This section contains the 2019 Remuneration Policy Guidelines defined by the Board of Directors on March 14, 2019 for Directors and Managers with strategic responsibilities.
The 2019 Remuneration Policy Guidelines contain no changes in their structure and related remuneration and incentive levels compared with what was previously described in the first section of the 2018 Remuneration Report examined by shareholders at the annual meeting of May 10, 2018, which was approved by favourable vote of 80.46% of those in attendance.

Policy unchanged on 2018

MARKET REFERENCES AND PEER GROUP

For the Chief Executive Officer and General Manager, the positioning of the Company's remuneration is assessed by comparing similar roles only within the international Oil & Gas industry, with regard to upstream activities in particular and in line with the company's strategy to increase its focus on this segment of the business. The median value of the remuneration of the Chief Executive Officer and General Manager in the Peer Group is also adjusted for differences in capitalisation compared with Eni.
The comparator group includes the main listed companies in the Oil & Gas industry, which are Eni's competitors at the international level and possess comparable business characteristics (Anadarko, Apache, BP, Chevron, ConocoPhillips, ExxonMobil, Marathon Oil, Shell, Equinor (formerly Statoil), and Total. More specifically, the Peer Group was determined on the basis of its representativeness of the Oil & Gas sector at the global level and its relative comparability with Eni with regard to operations and geographical areas of interest, while taking account of median corporate dimensions (in terms of capitalization, reserves, output).

Chief Executive Officer and General Manager

Chairman and the Non-Executive Directors

In line with this approach these companies also make up the Peer Group used for the relative comparison of Eni's performance under the new Long-Term Share Incentive Plan. Accordingly, the selection criteria required consideration only of those companies that publish data on the NPV of proven reserves that are comparable with Eni, using the calculation method defined by the SEC. For the Chairman and the Non-Executive Directors, the positioning of remuneration is assessed by comparing similar roles in the Top Italy group, which is composed of the main companies listed on the FTSE MIB (Assicurazioni Generali, Atlantia, Enel, Intesa Sanpaolo, Leonardo, Luxottica, Mediaset, Mediobanca, Poste Italiane, Snam, Terna, TIM, Unicredit).

Managers with strategic responsibilities

For Managers with strategic responsibilities, the positioning of remuneration is assessed by comparing roles of the same level of managerial complexity and responsibility within industrial corporations in national and international markets.
Comparisons of remuneration have been conducted with the help of the advisory firms Mercer, Willis Towers Watson, and Korn Ferry-Hay Group.

CHAIRMAN OF THE BOARD OF DIRECTORS

Fixed remuneration

The 2019 Remuneration Policy Guidelines for the Chairman call for total fixed remuneration of €500,000 gross, which includes €90,000 gross for the position, as determined by the shareholders in their meeting of April 13, 2017, and for remuneration for exercise of delegated powers[23] in the amount of €410,000 gross annually, unchanged compared with 2018, taking account of the outcome of the comparative analyses of remuneration related to median levels in the benchmark market and the complexity of the position.
There is also a life insurance policy and an insurance policy against permanent disability due to injury or illness contracted in the workplace or elsewhere.
No specific severance payments are provided, nor do any agreements exist for indemnities in the case of resignation or early termination of office[24].

NON-EXECUTIVE DIRECTORS

Remuneration for participating on Board Committees

The 2019 Remuneration Policy Guidelines for Non-Executive and/or Independent Directors provide for the maintenance of additional annual remuneration[25] for participating on Board Committees, as authorised by the Board of Directors on April 13, 2017 and in line with the median levels recorded in the reference market, taking due account of the commitment in terms of frequency and duration of meetings, as follows:
- for the Control and Risk Committee, remuneration of €70,000 for the Chairman and €50,000 for other members;
- for the Remuneration Committee and the Sustainability and Scenarios Committee, remuneration of €50,000 for the Chairman and €35,000 for other members;
- for the Nomination Committee, remuneration of €40,000 for the Chairman and €30,000 for other members.

No specific severance payments are provided for Non-Executive Directors, nor do any agreements exist for indemnities in the case of resignation or early termination of office[26].

CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER

The 2019 Remuneration Policy Guidelines for the Chief Executive Officer and General Manager of the Company are in line with the 2018 Remuneration Guidelines and reflect the decisions of the Board of Directors of June 19 and July 27, 2017 as well as the model of organization and corporate governance adopted by the Company.
In particular, the 2019 remuneration policies are in line with the outcome of the comparative studies conducted by looking at the total median remuneration of the companies within the Peer Group, appropriately reduced as indicated in the Summary.

(23) Non-executive powers connected with the performance of guarantor duties within the internal control system, managing the relationship between the head of the Internal Audit Unit and the Board. The Chairman also performs the representation duties set out in the By-laws, managing the Company's institutional relations in Italy in coordination with the Chief Operating Officer.
(24) In consideration of the reference to this Report in the 2018 Report on Corporate Governance and Shareholding Structure, which is available in the Governance section of the Company's website, this information is being published in accordance with Article 123-bis, paragraph 1, letter i), of the Consolidated Law on Financial Intermediation (agreements between companies and directors, members of the control body or supervisory council which envisage indemnities in the event of resignation or dismissal without just cause, or if their employment contract should terminate as the result of a takeover bid).
(25) This remuneration supplements that approved by the Shareholders' Meeting on April 13, 2017 for Directors in the amount of €80,000 gross per year.
(26) Information provided in accordance with Article 123-bis, paragraph 1, letter i), of the Consolidated Law on Financial Intermediation, as specified under note 24 above.

FIXED REMUNERATION

Annual fixed remuneration (FR) authorized by the Board of Directors on June 19, 2017 for the position of Chief Executive Officer and of General Manager totals €1,600,000 gross, which includes: i) annual remuneration of €600,000 gross for the position of Chief Executive Officer, including annual remuneration of €80,000 gross for the position of member of the Board as approved by the shareholders on April 13, 2017; ii) annual remuneration of €1,000,000 gross for the senior management position of General Manager. This remuneration encompasses any emoluments due for participation in the meetings of the boards of directors of other Eni subsidiaries and/or shareholdings. As an Eni senior manager, the General Manager is also entitled to receive an allowance for travel, in Italy and abroad, in line with the applicable provisions under the relevant national collective bargaining agreement for senior managers of industrial companies and with supplementary company-level agreements.

VARIABLE REMUNERATION: SHORT-TERM INCENTIVES WITH DEFERRAL

The Short-term Incentive Plan with deferral, as approved by the shareholders on April 13, 2017 within the scope of the Remuneration Policy Guidelines and as described in the 2018 Remuneration Report, calls for a portion of the incentive to be paid annually and a portion to be deferred for three years as described below.
The 2019 Short-term Incentive with deferral is tied to achieving the 2018 targets set by the Board on March 15, 2018.
Achievement of the targets is assessed net of any variable, exogenous effects (e.g. oil and gas prices or euro/dollar exchange rates) and in application of a predetermined method of gap analysis as approved by the Remuneration Committee.
The 2019 targets approved by the Board on March 14, 2019 for the 2020 short-term variable incentive system with deferral call for maintenance of a structure that is focused on essential milestones in line with the Strategic Plan and balanced in respect of the interests of the various stakeholders.
The structure and weight of the various targets are shown in the table 4. The value of each target is in line with the budgeted figure.
The performance parameters used for the definition of the Short-Term Incentive Plan for the Chief Executive Officer and General Manager are closely linked to the corporate strategy, as they are intended to measure the achievement of annual budget targets with a view to long-term sustainability.

Annual objectives linked to corporate strategy

TABLE 4 - 2018 TARGETS FOR THE 2019 SHORT-TERM INCENTIVE PLAN WITH DEFERRAL

ECONOMIC AND FINANCIAL RESULTS (25%)	OPERATING RESULTS AND SUSTAINABILITY OF ECONOMIC RESULTS (25%)	ENVIRONMENTAL SUSTAINABILITY AND HUMAN CAPITAL (25%)	EFFICIENCY AND FINANCIAL STRENGTH (25%)
INDICATORS Earning Before Tax (12.5%) Free Cash Flow (12.5%)	**INDICATORS** Hydrocarbon production (12.5%) Exploration resources (12.5%)	**INDICATORS** CO_2 emissions (12.5%) Severity Incident Rate (12.5%)	**INDICATORS** ROACE (12.5%) Debt/EBITDA (12.5%)
LEVERAGE Upstream expansion Strengthen Gas & Power operations Resilience in downstream Green business	**LEVERAGE** Fast track approach Expanding exploration acreage Diversification	**LEVERAGE** Decarbonization HSE and sustainability	**LEVERAGE** Financial discipline Efficiency of operating costs and G&A Optimisation of working capital

In particular:

- the indicators **EBT** and **FCF** are measures of Eni's ability to ensure the profitability of our businesses and to provide sufficient cash flows to provide a return on investment and pay dividends, even in particularly challenging contexts. In this regard, Eni seeks to constantly expand our business, beginning with the upstream segment, by way of a targeted exploration strategy, organic growth in production generated at particularly competitive cost points, and dual-exploration model that allows us to quickly monetize reserves. In the mid-downstream segment, reinforcement is pursued by expanding our LNG portfolio and our base of retail customers, while in the downstream segment there is a constant focus on optimising our industrial structure and developing the green business;

Financial targets

Operating results and sustainability of economic results

- the upstream indicators of **hydrocarbon production** and **exploration resources** measure the operating efficiency of a strategy centred around the continuous replacement of the portfolio of resources and taking full advantage of that portfolio by way of a "dual-exploration" model and the "fast-track" implementation of discoveries;

Environmental sustainability and human capital

- the indicators of **CO_2 emissions** and the **Severity Incident Rate (SIR)** reflect Eni's HSE priorities and the central importance of our commitment to protecting the environment and to individual safety. In particular, within the scope of our decarbonization strategy, Eni seeks to: (i) reduce the carbon footprint of our activities, beginning with direct upstream emissions, fugitive emissions, and the elimination of the process gas flaring; (ii) maintain low-carbon portfolio that is resilient in a range of contexts; and (iii) develop green businesses with a constant focus on research. These efforts are consistent with the target set for 2025 as reported to investors.
  With regard to SIR, prevention and risk minimization are cornerstones of Eni's operations in our commitment to achieving constant improvements in safety for all workers and to expressing this commitment in the process of assessing the performance of senior management. In particular, use of an SIR focuses Eni's commitment on reducing serious injuries given that it calculates the frequency of injuries over the number of hours worked, but weighted for the actual severity of the incident;

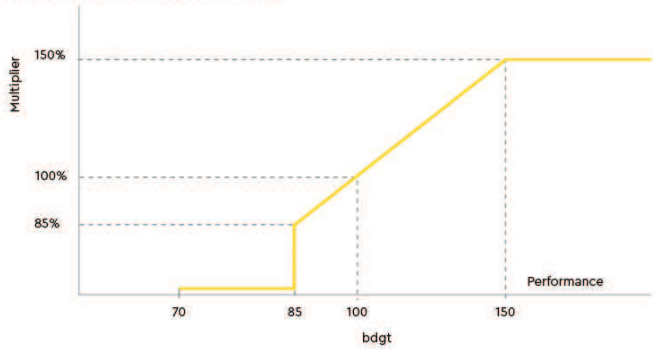
Efficiency and financial strength

- the indicators **ROACE** and **debt-to-EBITDA** measure the company's financial discipline and the quality of our financial structure and earnings, which translates into a careful selection of investments, into efficiency and cost control, and into a rapid return on investment. All of these efforts enable us to reinforce our resiliency even during economic downturns.

Performance scale and annual multiplier

In line with the general Remuneration Policy principles, the STI Plan features the characteristics described below. Each target is predetermined and measured based on a performance scale of 70-150 points (target=100) in relation to the weight assigned to each (a score below 70 points implies a performance multiplier of zero). For purposes of the total incentive award, the minimum overall performance is 85 points. In order to allow for the promotion of initiatives of business development, a multiplier of 1.1 may be applied to the overall performance score, in case of business portfolio development initiatives not included in the budget, but defined by the Board of Directors at the time of their approval as particularly effective for the implementation of the strategic guidelines of the 2019-2022 Plan, if considered by the Remuneration Committee of particular relevance for the annual performance as well. The score in the performance scale will not exceed 150 points.
The total incentive is determined in reference to a minimum multiplier (performance = 85), target multiplier (performance = 100) and maximum multiplier (performance = 150), equalling 85%, 100% and 150%, respectively, to be applied in relation to the performance achieved by Eni during the prior year.
The chart below shows the value of the multiplier as a function of performance.

CHART 9 – TOTAL INCENTIVE MULTIPLIER



The total incentive (TI) is calculated using the following formula.

$$TI = FR \times I_{Target} \times Multiplier$$

Where "I_{Target}" is the incentive percentage at target performance level, which is set to 150% of total fixed remuneration for the Chief Executive Officer.
The incentive is divided in two portions:

Portion paid annually

1) a portion paid annually (I_{Year}) equal to 65% of the total incentive.

$$I_{Year} = TI \times 65\%$$

The levels of the fraction of the incentive payable during the year, depending on the performance levels achieved, are shown in the table below[27].

TABLE 5 - INCENTIVE FRACTION PAYABLE DURING THE YEAR

Average 3-year performance	<85	85 threshold	100 target	150 max
Deferred incentive (in % of Fixed Rem.)	0%	83%	98%	146%

Deferred portion subject to further performance conditions over the three-year period

2) a deferred portion ($I_{Deferred}$ equal to 35% of the total incentive, subject to further performance conditions during a three-year vesting period, as shown in the figure below.

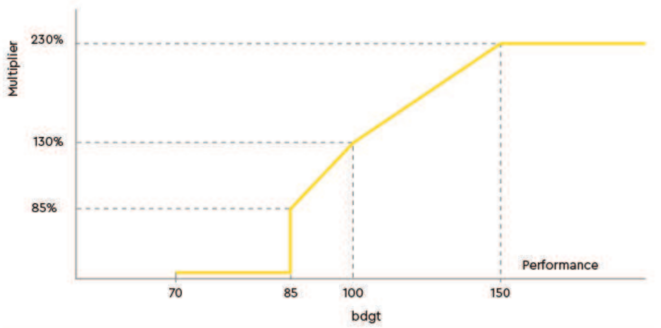
STI Performance

CHART 10 – STI PLAN - TIMELINE

Performance scale and average three-year multiplier

The deferred portion payable at the end of the vesting period is determined by multiplying the initial deferred portion by the payment multiplier given by the average of the annual multipliers recorded over the three-year period in relation to the performance achieved based on the chart of annual Eni targets.
The multiplier of the deferred portion depends on the performance achieved as shown below.

CHART 11 – DEFERRED PORTION MULTIPLIER



(27) The incentive values as a % of fixed remuneration shown in the table were calculated as follows:
Threshold: 83% = 65% x (150% x 85%)
Target: 98% = 65% x (150% x 100%)
Max: 146% = 65% x (150% x 150%)

The Deferred Incentive ($I_{Deferred}$) payable at the end of the three-year deferment period is calculated using the following formula.

$$I_{Deferred} = 35\% \times TI \times Multiplier$$

The levels of the payable deferred portion, depending on the performance levels achieved throughout the three-year period, are shown in the table below[28].

TABLE 6 – LEVELS OF PAYABLE DEFERRED PORTION

Average 3-year performance	<85	85 threshold	100 target	150 max
Deferred incentive (in % of Fixed Rem.)	0%	38%	68%	181%

Objectives of LTI share-based Plan

VARIABLE REMUNERATION: LONG-TERM SHARE INCENTIVES

The 2017-2019 Long-Term Share Incentive Plan approved by the shareholders on April 13, 2017, as described in the Remuneration Report and in the Disclosure Document published in 2017, ensures the following objectives in line with international best practices:

- strengthening the culture of management of business risk from the perspective of shareholders by incentivizing through share ownership;
- setting a more challenging minimum incentive threshold, positioned at median level;
- aligning performance conditions with the Long-Term expectations of shareholders, by way of:
  - the assessment of performance of the Company's Total Shareholder Return over a three-year period compared with that of the reference stock market index, compared with the same performance of the main international competitors (the Peer Group);
  - incentivize the capacity to develop industrial assets, measured using the increase in net present value of hydrocarbon reserves over the medium to long term (in accordance with standard SEC assessment methodology), measured in relative terms compared with the Peer Group.

The Plan provides for three annual awards starting from 2017, each with a three-year vesting period, in accordance with the timeline below.

Performance period Equity-based LTI Plan

CHART 12 - EQUITY-BASED LTI PLAN – TIMELINE

The Plan is subject to performance conditions during the three-year vesting period, in accordance with the following parameters and related weightings:

1) The difference between the TSR of Eni shares and the TSR of the FTSE MIB index of Borsa Italiana, adjusted by the Eni Correlation Coefficient, compared with the equivalent adjusted TSR measure for each company in the Peer Group, as shown in the following formula (50% weighting):

$$TSR_{CO} - (TSR_{IDX} \times \rho_{CO,IDX})$$

(28) The incentive values as a % of fixed remuneration shown in the table were calculated as follows:
Threshold: 38% = 35% x (150% x 85%) x 85%
Target: 68% = 35% x (150% x 100%) x 130%
Max: 181% = 35% x (150% x 150%) x 230%

where:
TSR_{CO}: TSR of Eni or of one of the companies of the Peer Group;
TSR_{IDX}: TSR of the reference stock market index of the company to which TSRco. applies;
$\rho_{CO,IDX}$: Correlation coefficient between the performance of the share and the performance of the reference market (FTSE Mib, S&P 500, FTSE 100, CAC 40, AEX, OBX).
This indicator was introduced in order to neutralize the potential effects on the performance of each share of developments in the respective stock market. More specifically, this neutralisation is proportionate to the correlation between the stock and the market over the same three-year period by using the correlation coefficient.

Neutralisation of TSR performance with respect to financial market developments

2) Net Present Value (NPV) of proven reserves vs. the Peer Group, measured in terms of the annual percentage change, calculating the average annual performance over the three-year period (50% weighting).

The reference Peer Group is described in the section "Market References and Peer Group" (Anadarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Equinor and Total).
For the Chief Executive Officer and General Manager, the Plan conditions provide for the annual award of shares for a value equivalent to 150% (I_{target}) of total fixed remuneration (FR), using the following formula:

$$\text{No. of Awarded shares} = \frac{FR \times \%I_{Target}}{Price_{Attr}}$$

where the price of the award ($Price_{Attr}$) is calculated as the average of the daily official prices (source: Bloomberg) recorded in the four months before the date of the Board of Directors meeting held annually to approve the plan rules and the award to the Chief Executive Officer and General Manager.
The granting of shares at the end of the three-year vesting period is determined using a final multiplier to be applied to awarded shares (calculated as the weighted average of the multipliers of each parameter) determined over the vesting period in relation to the position reached in the Peer Group.

Each multiplier may be between zero and 180%, with a threshold set at a median level, in accordance with the scale shown below.

Relative performance scale (ranking) and multiplier

TABLE 7 - PERFORMANCE SCALE - MULTIPLIER

Ranking										
1°	2°	3°	4°	5°	6°	7°	8°	9°	10°	11°
Multiplier										
180%	160%	140%	120%	100%	80%	0%	0%	0%	0%	0%
					Median positioning					

Grantable shares are calculated using the following formula:

$$\text{No. of Granted shares} = \text{No. of Awarded shares} \times \text{Multiplier}$$

The table below shows the thresholds, targets and maximum value of shares (as a percentage of fixed remuneration) grantable to the Chief Executive Officer and General Manager at the end of the vesting period, net of the change in share price for the period[29].

(29) The incentive values as a % of fixed remuneration shown in the table were calculated as follows:
Threshold: 40% = 150% x 26,6%
Target: 150% = 150% x 100%
Max: 270% = 150% x 180%

TABLE 8 - SHARE VALUES

Weighted average 3-year performance	<26.6	26.6 threshold[a]	100 target	180 max
Value of shares (in % of Fixed Rem.)	0%	40%	150%	270%

(a) Achieved, for example, if the NPV indicator of proven reserves reaches the minimal level (6th place) for at least two years.

Lock up of the shares granted for one year

For senior managers still in service, the rules of the Plan state that 50% of the shares granted at the end of the vesting period are to remain restricted for one year from the granting date.

NON-MONETARY BENEFITS

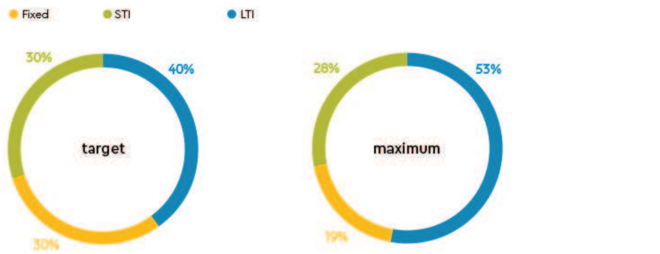
There is a life insurance policy and an insurance policy against permanent disability due to injury or illness contracted in the workplace or elsewhere.
Also provided, as per provisions contained in the national collective bargaining agreement and the supplementary company agreements for Eni senior managers, is enrolment in the supplementary pension plan (FOPDIRE[30]) and in the supplementary health plan (FISDE[31]) together with a company car for business and personal use.

PAY MIX

Pay mix with a dominant weighting attributed to the variable long-term component

The remuneration package for the Chief Executive Officer and General Manager includes a fixed component, a short-term variable component and a long-term variable component, which comprises a short-term incentive deferral and long-term share incentive determined using internationally recognized methodologies for remuneration benchmarks.
The pay mix, calculated by considering fixed remuneration as the base, is weighted significantly towards the variable components, with a dominant weighting attributed to the long-term component, as shown in the figure below.

CHART 13 - CEO/GM PAY MIX



PAYMENTS DUE IN THE EVENT OF TERMINATION OF OFFICE OR EMPLOYMENT[32]

In line with the European Commission Recommendation

For the Chief Executive Officer and General Manager, based on a proposal by the Remuneration Committee and having heard the opinion of the Board of Statutory Auditors, the Board of Directors resolved on June 19, 2017 to maintain the following severance packages in the event of termination of office or of employment:

1) an indemnity for the administrative relationship in the event of early termination and/or non-renewal of the employment relationship, including in the event of resignation due to a substantive reduction of delegated powers. This indemnity has been set at two years of fixed remuneration for the position, for a total of €1,200,000, in accordance with European Commission Recommendation no. 385 of April 30, 2009;

(30) Defined-contribution and individual-capitalization contractual pension fund (www.fopdire.it).
(31) Fund that reimburses healthcare spending for active or retired senior management and their family members (www.fisde-eni.it).
(32) Information provided in accordance with Article 123-bis, paragraph 1, letter i), of the Consolidated Law on Financial Intermediation, as specified under note 24 above.

2) an indemnity in the event of the consensual termination of the management relationship in relation to termination of the associated administrative position in addition to standard post-employment benefits. This indemnity has been set, taking due account of the provisions of the appropriate national collective bargaining agreement, in accordance with the parameters and policies defined for Eni Managers with strategic responsibilities, equal to two years of fixed and variable remuneration for the senior management position, excluding the Long-Term Share Incentive Plan and with mutual exemption from any obligation of advance notice, without payment of the related indemnity (equal to an annuity). In reference to criterion 6.C.1, letter g), of the Italian Corporate Governance Code, this indemnity is not due in the following cases: i) dismissal for "just cause" under Article 2119 of the Italian Civil Code; ii) resignation as Chief Executive Officer prior to the expiry of the term in office not justified by a reduction of delegated powers; iii) in the event of death as governed by Article 2122 of the Italian Civil Code; iv) dismissal from the role of Chief Executive Officer for just cause.

Consistent with protections provided for in national collective bargaining agreement for executives

With reference to long-term incentives, in the event of early termination for the Chief Executive Officer and General Manager, due to resignation and not justified by a substantial reduction in powers or of termination for just cause, all rights to the payment and grant of incentives shall lapse. In the event of termination related to expiry of the term on the Board of Directors without renewal[33], the long-term incentives awarded during the term shall vest in accordance with the terms and conditions established by the respective regulations.

Protection from competitive risks connected with termination of employment

In order to safeguard the company's interests from potential competitive risks related to the great international importance of the professional and managerial background of the Chief Executive Officer and General Manager, on July 27, 2017, the Board of Directors, based on the recommendation of the Remuneration Committee and having obtained a favourable opinion of the Board of Statutory Auditors, has also resolved to maintain the non-competition agreement in place since 2014, while extending the clause to geographical areas and industries that have taken on greater strategic importance over the last three years.

More specifically, the agreement, which can be activated at the sole discretion of the Board through the exercise of an option right[34], has the following characteristics: i) a validity of 12 months post-termination; ii) restricted markets extended from Exploration & Production to also include the Midstream sector; iii) 18 restricted nations with the addition of Mexico to those that were envisaged during the previous term (Algeria, Angola, Congo, Egypt, Ghana, Indonesia, Iraq, Italy, Kazakhstan, Libya, Mozambique, Nigeria, Norway, Russia, UK, USA, Venezuela); iv) additional confidentiality and non-solicit restrictions.

Payment for the non-competition agreement calls for the retention of two components calculated based on current remuneration levels and the extension of commitments undertaken: i) a fixed component in the amount of €1,800,000; ii) a variable component to be determined by the Board of Directors, based on a recommendation by the Remuneration Committee, in line with the average annual performance over the previous three years, as follows: for performance below the target, this component will be set to zero; for performance on target, it will be €500,000; and for maximum performance, it will be €1,000,000. The average annual performance shall be calculated on the basis of final results for the year within the scope of the short-term incentive plan.

MANAGERS WITH STRATEGIC RESPONSIBILITIES

For Managers with strategic responsibilities, the 2019 Remuneration Policy Guidelines are unchanged on those for 2018, maintaining remuneration plans that are strictly in line with those of the Chief Executive Officer and General Manager, to better guide and align managerial action with the objectives set out in the Company's Strategic Plan, and with the provisions and protections laid down by national collective bargaining agreement for senior managers.

In particular, the Long-Term Share Incentive Plan and Short-Term Variable Incentive Plan with deferral – intended for the Chief Executive Officer and General Manager will also apply to Managers with strategic responsibilities.

(33) It should be noted that, under Italian law, directors of joint-stock companies may not be appointed for terms of longer than three financial years, and their terms expire on the date of the meeting of shareholders held to approve the financial report for the last financial year of their term (Article 2383, second paragraph, of the Italian Civil Code).

(34) The option right, for a total of €500,000, was paid in full as reported on page 24 of Eni's 2015 Remuneration Report (Section II, Table 1, note 4 b). The option right was exercized by the Board of Directors, on proposal of the Remuneration Committee, with deliberation of March 14, 2019.

FIXED REMUNERATION

Fixed remuneration differentiated by level of responsibility and complexity of position

Fixed remuneration is based on roles and responsibilities assigned taking into consideration a graduated and a generally median to below-median positioning versus national and international executive markets for comparable roles. It may be updated periodically, during the annual salary review for all managers.
Given current market comparators and trends, the 2019 Guidelines provide for a selective approach to salary reviews, while maintaining appropriate levels to ensure competitiveness and motivation.
More specifically, proposed actions will include measures to adjust fixed/one-off remuneration for those in positions that have seen a significant increase in responsibility or scope, and to address retention risk and reward excellent performance.
In addition, in their capacity as Eni officers, Managers with strategic responsibilities are entitled to receive allowances due for travel in Italy and abroad, in line with applicable provisions of the Italian national collective bargaining agreement for senior managers and supplementary Company agreements.

VARIABLE INCENTIVE PLANS

Short-term Variable Incentive Plan with deferral

Close consistency with targets and incentive plans for CEO/GM

The Short-Term Incentive Plan with deferral, already described for the Chief Executive Officer and General Manager, will be implemented in 2019.
The targets set for Managers with strategic responsibilities are consistent with those assigned to the Chief Executive Officer and General Manager, on the basis of the same balancing of stakeholder interests, in addition to relevant individual targets, consistent with the responsibilities of the role and the provisions of the Company's Strategic Plan. For Managers with strategic responsibilities, the target incentive levels for the Short-term Variable Incentive Plan differ depending on the role's level of responsibilities and complexity up to 100% of fixed remuneration, with a maximum incentive level payable for the annual and deferred portions of 98% and 121% of fixed remuneration, respectively.

Long-term Variable Incentive Plan

Managers with strategic responsibilities participate in the 2017-2019 Long-Term Performance Share Plan (LTI) approved by the Shareholders' Meeting on April 13, 2017.
The Plan is directed at managers who are critical for the business and envisages three annual awards, starting in 2017, with the same performance conditions and characteristics as those described above for the Chief Executive Officer and General Manager.
For Managers with strategic responsibilities, the value of the shares to be awarded each year differs depending the level of their role and is limited to a maximum of 75% of fixed remuneration, with the maximum grant corresponding to 135% of fixed remuneration, calculated with reference to the award price of the shares.

NON-MONETARY BENEFITS

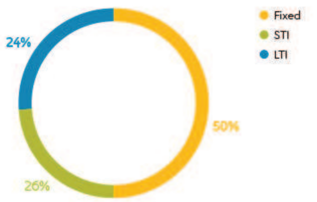
In line with national collective bargaining agreement and supplementary Company-level agreements for Eni managers, the Policy Guidelines provide for life and disability insurance cover (due to workplace or other injury or illness), as well as enrolment in the supplementary pension plan (FOPDIRE) and health plan (FISDE), together with a company car for business and personal use, and the possible assignment of housing based on operational and mobility requirements.

PAY MIX

Balance between fixed and variable remuneration in relation to level of responsibility and impact on business

In line with market best practices, as well as the valuation methods used for the Chief Executive Officer and General Manager the average target pay mix of the remuneration package for Managers with strategic responsibilities who are eligible for the Short-Term Monetary Plan with deferral and the Long-Term Performance Share Plan) features a balance between fixed and variable components that is weighted towards medium-long term variable incentives.

CHART 14 - PAY MIX MSR



PAYMENTS DUE IN THE EVENT OF CONSENSUAL TERMINATION OF EMPLOYMENT

Managers with strategic responsibilities, as well as Eni senior managers, are entitled to severance benefits for employment termination established by law and applicable national collective bargaining agreements, together with any termination indemnities agreed on an individual basis, in accordance with the criteria established by Eni for cases of early termination, within the limits of protections envisaged by applicable national collective bargaining agreements and consistent with application criterion 6.C.1, letter g) of the Italian Corporate Governance Code. These criteria take into account the position held, statutory retirement age and actual age of the manager at the time employment is terminated and the annual remuneration received. For cases of termination that present high competitive risks relating to the nature of the position, agreements may contain additional non-compete clauses with payments defined in relation to remuneration level, scope, duration and effectiveness of the agreement.

Consistent with protections provided for in national collective bargaining agreement for executives

SECTION II - REMUNERATION AND OTHER INFORMATION

Implementation of the 2018 remuneration policies

Implementation of the 2018 remuneration policies for Directors and Managers with strategic responsibilities, as verified by the Remuneration Committee in conjunction with its periodic assessment as called for the Corporate Governance Code, was in line with the 2018 Remuneration Policy approved by the Board of Directors on March 15, 2018, taking account of the provisions of the resolutions of the Board of Directors of April 13, 2017 and June 19, 2017 concerning, respectively, remuneration for Non-Executive Directors serving on Board committees and the remuneration of Directors with delegated powers.

VERIFICATION OF 2017 PERFORMANCE FOR THE PURPOSE OF INCENTIVES PAID AND/OR AWARDED IN 2018

This section covers: i) verification of results for 2017, as approved by the Board of Directors on March 15 and May 24, 2018 for the purpose of incentives earned and payable and/or awardable in 2018 to the Chief Executive Officer and General Manager and other Managers with strategic responsibilities.

SHORT-TERM INCENTIVE (STI) PLAN 2018

The 2018 STI Plan calls for the vesting of an incentive, upon verification of performance levels related to targets set for 2017, divided into a 65% fraction payable in 2018 and a 35% deferred portion that is awardable in 2018 and subject to the performance conditions established in the plan over a three-year vesting period.

More specifically, the verified performance related to targets assigned in 2017 to the Chief Executive Officer and General Manager was approved by the Board, based on a recommendation by the Remuneration Committee, on March 15, 2018 and resulted in a performance score of 134 points on the measurement scale used, the target and maximum performance of which are 100 and 150 points, respectively.

The table shows the weightings and performance level achieved for each target.

TABLE 9 - VERIFICATION OF 2017 TARGETS

Performance parameters	% weight	Result	Unit of measurement	Min 70	Budget 100	Max 130	Over performance 150	Performance score	Weighted score
i. Economic and financial results	**25.0**								**37.2**
EBT (Earning Before Tax) adjusted	12.5	5.5	bln €					150.0	18.7
Free cash flow	12.5	6.0	bln €					148.0	18.5
ii. Operating performance and sustainability of economic results	**25.0**								**26.8**
Hydrocarbon production	12.5	1,816	kboed					80.0	10.0
Exploration resources	12.5	1,027	mn boe					134.1	16.8
iii. Environmental sustainability and human capital	**25.0**								**33.7**
Severity Incident Rate (SIR) – employees and contractors - weighted	12.5	19.0	(*)					150.0	18.7
CO_2 emissions/UPS output	12.5	22.2	tCO_2eq/kboe					120.0	15.0
iv. Efficiency and financial strength	**25.0**								**36.3**
ROACE (Return On average Capital Employed) adjusted	12.5	4.67	%					150.0	18.8
Net Debt/EBITDA adjusted	12.5	0.81	index					140.0	17.5
Total	**100.0**								**134.0**

(*) (Total recordable injuries weighted for severity/hours worked) x 1,000,000.

The verification of targets was conducted net of exogenous variables (e.g. oil and gas prices and the euro-dollar exchange rate) using the gap-analysis approach approved by the Remuneration Committee. The following are the main results for the various performance targets:

- EBT: performance here was achieved by way of improvements to operations particularly in the mid-downstream sector, and reductions in costs – particularly in the upstream sector – and in general and administrative expenses.
- Free cash flow: this performance was achieved by improving operations and efforts to optimize working capital. In order to measure performance, the figure was also supplemented with the repayment of financial liabilities connected with portfolio transactions.
- Hydrocarbon production: this performance was penalised by the shutdown of Val d'Agri, unplanned shutdowns in Norway, Kazakhstan and the United States and the increase in bunkering and sabotage in Nigeria.
- Exploration resources: exploration resources were added, particularly in Mexico, Egypt and Indonesia, totalling 1.0 billion BOE.
- Severity Incident Rate (SIR), a total recordable incident rate per employee and contractor for millions of worked hours, which weighs injuries on the basis of severity: it declined by 56% compared with 2016, consolidating the trend of improvement seen in recent years, including in relation to the positioning of our competitors.
- CO_2 emissions/operated upstream production: this indicator has fallen 3% compared with 2016 thanks to a reduction in fugitive emissions, to energy-efficiency efforts, and to the start of new flaring-down projects.
- ROACE: this performance was achieved by improving financial performance, including the reduction of the tax rate.
- Debt-to-EBITDA: this performance was achieved by improving financial performance.

DEFERRED MONETARY INCENTIVE (DMI) PLAN 2015-2017

Payment DMI 2015

The 2015-2017 DMI Plan calls for three annual awards, and for the first of these (2015), on March 15, 2018, the Board of Directors, as verified and recommended by the Remuneration Committee, approved 2017 EBT for Eni at the maximum performance level, resulting in an annual multiplier of 170%.
As a result, given the already verified performance levels of 2015 and 2016, the three-year average multiplier, which is to be applied to incentives awarded in 2015 for payment in 2018, came to 170%.
The table below shows the performance levels achieved during the vesting period.

TABLE 10 - ASSIGNMENT DMI 2015 - EBT 2015-2017

Target EBT (billion €)	Multiplier 2015	Multiplier 2016	Multiplier 2017	Final multiplier for 2018 payment
EBT ≥ budget +0.5	170%	170%	170%	3-year average 170%
budget ≤ EBT < budget +0.5	130%	130%	130%	
budget -0.5 ≤ EBT < budget	70%	70%	70%	
EBT < budget -0.5	0%	0%	0%	

LONG-TERM MONETARY INCENTIVE (LTMI) PLAN 2014-2016

2015 LTMI paid

The 2014-2016 LTMI Plan calls for three annual awards, and for the second of these (2015), on March 15 and May 24, 2018, the Board of Directors, as verified and recommended by the Remuneration Committee, approved the performance for the 2017 targets of Total Shareholder Return and Net Present Value of proven reserves at seventh and fifth place, respectively, within the Peer Group for an annual multiplier of 28%.
As a result, given the already verified performance levels of 2015 and 2016, the three-year average multiplier, which is to be applied to incentives awarded in 2015 for payment in 2018, came to 63%.
Table 11 shows the positioning achieved during the vesting period.

TABLE 11 - PAYMENT LTMI 2015 - TSR AND NPV PROVEN RESERVES 2015-2017

Positioning in Peer Group	2015		2016		2017		Final multiplier for payment 2018
	TSR 60%	NPV 40%	TSR 60%	NPV 40%	TSR 60%	NPV 40%	
1°	130%	130%	130%	130%	130%	130%	
2°	115%	115%	115%	115%	115%	115%	
3°	100%	100%	100%	100%	100%	100%	
4°	85%	85%	85%	85%	85%	85%	
5°	70%	70%	70%	70%	70%	70%	
6°	0%	0%	0%	0%	0%	0%	
7°	0%	0%	0%	0%	0%	0%	3-year average
Annual multiplier	121%		40%		28%		63%

LONG-TERM SHARE INCENTIVE (LTI) PLAN 2017-2019

2018 LTI awarded

The 2017-2019 equity-based LTI Plan calls for three annual awards, and for the second of these (2018) on October 25, 2018, the Board of Directors, as verified and recommended by the Remuneration Committee, approved the grant price of €16.0297, calculated in accordance with the parameters set under the plan (average official daily price over the four months prior to the month in which the Board of Directors annually approves the Plan Rules and the award).

REMUNERATION PAID AND/OR AWARDED IN 2018

In this section, we describe the remuneration paid and/or awarded in 2018 to the Chairman of the Board of Directors, to Non-Executive Directors, to the Chief Executive Officer and General Manager, and to other Managers with strategic responsibilities in accordance with the 2018 remuneration policies and in relation to the performance levels achieved during the period in which they held their respective roles.

Remuneration paid/awarded in 2018 is shown in the tables of Section II.

CHAIRMAN OF THE BOARD OF DIRECTORS EMMA MARCEGAGLIA

Fixed remuneration

The Chairman was paid the fixed remuneration for the role and for the powers granted by the shareholders on April 13, 2017 and by the Board of Directors on June 19, 2017. For details of remuneration paid, see Table 1 in the section "Fixed remuneration".

Non-monetary benefits

The Chairman, in accordance with the resolution of the Board of Directors of June 19, 2017, was granted a life insurance policy and an insurance policy against permanent disability due to injury or illness contracted in the workplace or elsewhere.

NON-EXECUTIVE DIRECTORS

The Non-Executive Directors were paid the fixed remuneration approved by the shareholders on April 13, 2017, in the amount of €80,000. Additional remuneration payable for participation on Board Committees, as approved by the Board of Directors on April 13, 2017.
These are detailed in Table 1 under the section "Remuneration for participation on the Committees".

CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER CLAUDIO DESCALZI

Fixed remuneration
The Chief Executive Officer and General Manager was paid the fixed remuneration approved by the Board of Directors on June 19, 2017.
For details of remuneration paid, see Table 1 in the section "Fixed remuneration".

2018 Annual Monetary Incentive and Short-Term Incentive with deferral
With reference to the Remuneration Policy in force during 2017, the Chief Executive Officer and General Manager earned the following incentives in the period from January 1 to December 31, 2017:
- 2014-2017 term, up to April 12, 2017, the Board of Directors on May 28, 2014, approved the procedures and parameters for determining the variable remuneration of the Chief Executive Officer and General Manager, corresponding to target and maximum levels of 100% and 130% of fixed remuneration of €1,350,000, determined on the basis of a performance scale of 85-130 points. Accordingly, in view of the performance achieved in 2017 (134 points, reduced to 130 as the maximum applicable score), an annual incentive of €491 thousand was awarded, prorated for the period from January 1, 2017 to April 12, 2017;
- 2017-2020 term, starting April 13, 2017, the Board of Directors, meeting on June 19, 2017, approved the procedures and parameters for determining the variable remuneration of the Chief Executive Officer and General Manager, providing that the total incentive is determined with reference to a minimum multiplier (result = 85), target (result = 100) and maximum (result = 150) respectively equal to 85%, 100% and 150% in the performance scale 85- 150, to be applied to a base incentive equal to 150% of the total fixed remuneration (€1,600,000). The total incentive is divided into a portion payable during the year and a deferred portion of 65% and 35% respectively. Accordingly, in relation to performance achieved in 2017 (134 points), an annual incentive (annual portion) of €1,506 thousand was earned, in addition to a deferred incentive (deferred portion) of €811 thousand, prorated for the period from April 13, 2017 to December 31, 2017.

2015-2017 Deferred Monetary Incentive
In 2018 the Chief Executive Officer and General Manager received the Deferred Monetary Incentive awarded in 2015, in the amount of €1,469 thousand in relation to the final multiplier for the vesting period (170%), as approved by the Board of Directors on March 15, 2018.

2014-2016 Long-Term Monetary Incentive
In 2018, the Chief Executive Officer and General Manager was paid the Long-Term Monetary Incentive awarded in 2015 in the amount of €851 thousand, in relation to the final multiplier for the vesting period (63%), as approved by the Board of Directors on May 24, 2018.

2017-2019 Long-Term Equity-based Incentive Plan
In 2018, the Chief Executive Officer and General Manager was awarded 149,722 Eni shares as approved by the Board of Directors on October 25, 2018. The number of shares awarded was determined based on 150% of the incentive to be applied to total fixed remuneration and an award price of €16.0297, calculated in accordance with the parameters of the Plan.

Non-monetary benefits
In line with the resolutions of the Board of Directors of June 19, 2017, the Chief Executive Officer and General Manager was granted a life insurance policy and an insurance policy against permanent disability due to injury or illness contracted in the workplace or elsewhere, as well as, in compliance with the provisions of Italy's national collective bargaining agreement and the supplementary company agreements for Eni senior managers, he was granted enrolment in the supplementary pension plan (FOPDIRE) as well as supplementary health plan (FISDE), together with a company car for business and personal use.

Summary of remuneration paid to the CEO/GM
Below a summary of all remuneration paid in 2018 to Claudio Descalzi in relation to his role as Chief Executive Officer and General Manager.

TABLE 12 – SUMMARY OF REMUNERATION PAID TO THE CEO/GM IN 2018
(thousands of euros)

Role	Fixed remuneration	Annual bonus[a]	Long-Term incentives[b]	Benefits	Total
Chief Executive Officer and General Manager	1,600	1,997	2,319	17	5,933

(a) Includes:
- pro-rated 2018 Annual Monetary Incentive (€491 thousand);
- pro-rated 2018 Short-Term Incentive (€1,506 thousand).

(b) Includes:
- Deferred Monetary Incentive awarded in 2015 (€1,468.8 thousand);
- Long-Term Monetary Incentive awarded in 2015 (€850.5 thousand).

MANAGERS WITH STRATEGIC RESPONSIBILITIES

Fixed remuneration

In 2018, within the context of the annual salary review process envisaged for all managers, selective adjustments were made to fixed remuneration for current Managers with strategic responsibilities, in cases of promotion to more senior levels, or in line with necessary market-driven adjustments. The total gross value of fixed remuneration paid in 2018 to Managers with strategic responsibilities is shown in Table 1 in the chapter “Compensation paid in 2018”, under the item “Fixed compensation”.

2018 Deferred Short-Term Incentive (STI) 2018

In 2018 Managers with strategic responsibilities were paid/awarded incentives, based on performance achieved in 2017. The total gross amount is shown in Table 2 in the chapter “Compensation paid in 2018”, under the items “Bonus for the year payable/paid” and “Bonus for the year - deferred”. In particular, the incentive is linked to performance against a range of metrics related to business and sustainability objectives (safety, environmental protection, stakeholder relations), as well as relevant individual targets, in relation to the scope of the responsibilities of the position, consistent with the provisions of the Eni Strategic Plan.

2015-2017 Deferred Monetary Incentive Plan

Managers with strategic responsibilities were paid in 2018 incentives awarded in 2015, on the basis of the final multiplier verified in the vesting period (170%), approved by the Board of Directors of March 15, 2018. The total gross value of the incentives paid is shown in Table 2 in the chapter “Compensation paid in 2018”, under the item “Bonus for previous years - payable/paid”.

2014-2016 Long-Term Monetary Incentive Plan

Managers with strategic responsibilities were paid in 2018 Long-Term monetary incentives awarded in 2015, on the basis of the final multiplier verified in the vesting period (63%), approved by the Board of Directors on May 24, 2018.
The total gross value of the incentives paid to Managers with strategic responsibilities is shown in Table 2 in the chapter “Compensation paid in 2018”, under the items “Bonus for the year - deferred” and “Bonus for previous years - payable/paid”.

2017-2019 Long-Term Share-based Incentive Plan

In accordance with the resolution of the Board of Directors at its meeting of October 25, 2018, managers with strategic responsibilities were granted the second award for the Plan. The aggregate number of shares awarded to managers with strategic responsibilities is shown in Table 3 of the chapter “Remuneration paid in 2018”, under the item “Eni shares awarded during the year”.

Severance indemnity for end-of-office or termination of employment

No Managers with strategic responsibilities terminated their employment in 2018.

Non-monetary benefits

For Managers with strategic responsibilities, in line with provisions in Italy’s national collective bargaining agreement and supplementary corporate agreements for Eni managers, the Policy Guidelines provide for enrolment in the supplementary pension plan (FOPDIRE) as well as in the supplementary health plan (FISDE), life and disability insurance cover, together with a company car for business and personal use.

Disclosure on verification of 2018 performance

VERIFICATION OF 2018 PERFORMANCE FOR THE PURPOSE OF INCENTIVES VESTED AND PAYABLE AND/OR AWARDABLE IN 2019

In this section, we describe verification of results for 2018 targets, as approved by the Board of Directors on March 14, 2019, for the purpose of incentives vested, payable or awardable in 2019 to the Chief Executive Officer and General Manager and to other Managers with strategic responsibilities.

SHORT-TERM INCENTIVE (STI) PLAN WITH DEFERRAL 2019

The new 2019 STI Plan calls for the vesting of an incentive, upon verification of performance levels related to targets set for 2018, divided into a 65% fraction payable in 2019 and a 35% deferred portion that is awardable in 2019 and subject to the performance conditions established in the plan over a three-year vesting period.

More specifically, the verified performance related to targets assigned in 2018 to the Chief Executive Officer and General Manager was approved by the Board, based on a recommendation by the Remuneration Committee, on March 14, 2019 and resulted in a performance score of 127 points on the measurement scale used, the target and maximum performance of which are 100 and 150 points, respectively.

The table shows the weightings and performance level achieved for each target.

TABLE 13 – VERIFICATION OF 2018 TARGETS

Performance parameters	% weight	Result	Unit of measurement	Min 70	Budget 100	Max 130	Over performance 150	Performance score	Weighted score
i. Economic and financial results	**25.0**								**37.6**
EBT (Earning Before Tax) adjusted	12.5	10.5	bln €					150.0	18.8
Free cash flow	12.5	6.7	bln €					150.0	18.8
ii. Operating performance and sustainability of economic results	**25.0**								**25.3**
Hydrocarbon production	12.5	1,851	kboed					70.0	8.7
Exploration resources	12.5	622	mn boe					133.0	16.6
iii. Environmental sustainability and human capital	**25.0**								**27.8**
Severity Incident Rate (SIR) – employees and contractors - weighted	12.5	49	(*)					72.0	9.0
CO_2 emissions/UPS output	12.5	21.4	tCO_2eq/kboe					150.0	18.8
iv. Efficiency and financial strength	**25.0**								**36.4**
ROACE (Return On average Capital Employed) adjusted	12.5	8.5	%					150.0	18.8
Net Debt/EBITDA adjusted	12.5	0.44	index					141.0	17.6
Total	**100.0**								**127.1**

(*) (Total recordable injuries weighted for severity/hours worked) x 1,000,000.

The following are the main results for the various performance targets.

- EBT: performance here was achieved by way of reductions in costs particularly in the upstream sector and improvements of margins and volumes in the mid-downstream sector also thanks to portfolio and assets restructuring.
- Free cash flow: the particularly high level was achieved thanks to a significant improvements of financial performance and efforts to optimize working capital.
- Hydrocarbon production: after the high levels achieved in 2018, and considering the high target levels, the performance was penalised by lower gas demand due to geopolitical and commercial problems in Libya, Venezuela and Ghana and unplanned shutdowns in the United States, Norway and Nigeria.

- Exploration resources: exploration resources were added, particularly in Egypt, Cyprus, Norway, Angola, Nigeria, Mexico and Indonesia totalling over 0.6 billion BOE, confirming the focus on exploration activities as a guarantee of organic growth.
- Severity Incident Rate (SIR) a total recordable incident rate per employee and contractor for millions of worked hours, which weighs injuries on the basis of severity: it increased reflecting the occurence of some severe incidents.
- CO_2 emissions/operated upstream production: this indicator has fallen 6% compared with 2017 thanks to a reduction in fugitive emissions from flaring and higher contribution from assets with lower emission intensity compared with the portoflio average.
- ROACE: this performance was mainly achieved by improving financial performance
- Debt-to-EBITDA: this performance was achieved by improving financial performance.

DEFERRED MONETARY INCENTIVE (DMI) PLAN 2015-2017

2016 DMI vested

The 2015-2017 DMI Plan calls for three annual awards, and for the second of these (2016), on March 14, 2019, the Board of Directors, as verified and recommended by the Remuneration Committee, approved the 2018 EBT for Eni at the maximum performance level, resulting in an annual multiplier of 170%.

As a result, given the already verified performance levels of 2016 and 2017, the three-year average multiplier, which is to be applied to incentives awarded in 2016 for payment in 2018, came to 170%.

The table below shows the performance levels achieved during the vesting period.

TABLE 14 – VESTED DMI 2016 – EBT 2016–2018

Target EBT (€bln)	Multiplier 2016	Multiplier 2017	Multiplier 2018	Final multiplier for payment 2019
EBT ≥ budget +0.5	170%	170%	170%	
budget ≤ EBT < budget +0.5	130%	130%	130%	3-year average
budget -0.5 ≤ EBT < budget	70%	70%	70%	170%
EBT < budget-0.5	0%	0%	0%	

2014-2016 LONG-TERM MONETARY INCENTIVE (LTMI) PLAN

Vesting of LTMI 2016

The 2014-2016 LTMI Plan calls for three annual awards, and for the third of these (2016), on March 14, 2019, the Board of Directors, as verified and recommended by the Remuneration Committee, approved the performance for the 2018 targets of Total Shareholder Return at second place within the Peer Group. The 2018 performance of the net present value of proven reserves will be examined by the Board at its meeting scheduled for May 2019 as soon as the data for the Peer Group are available.

LONG-TERM SHARE INCENTIVE (LTI) PLAN 2017-2019

2019 LTI awarded

The 2017-2019 equity-based LTI Plan calls for three annual awards, and for the third of these (2019), in a meeting planned for October 2019, the Board of Directors, as verified and recommended by the Remuneration Committee, will approve the award price calculated in accordance with the parameters set under the plan (average official daily closing price over the four months prior to the month in which the Board of Directors approved the award).

INCENTIVES VESTED AND PAYABLE AND/OR AWARDABLE IN 2019

This section describes the incentives vested and payable and/or awardable in 2019 to the Chief Executive Officer and General Manager and to other Managers with strategic responsibilities in relation to the verification of 2018 targets.

CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER CLAUDIO DESCALZI

2019 Short-Term Incentive with deferral

The Chief Executive Officer and General Manager earned an annual incentive (annual portion) of €1,981 thousand in addition to a deferred incentive (deferred portion) of €1,067 thousand, calculated using the procedures and parameters approved by the Board of Directors on June 19, 2017 and in relation to performance achieved in 2018 (127 points) as approved by the Board of Directors on March 14, 2019.

2015-2017 Deferred Monetary Incentive

The Chief Executive Officer and General Manager earned the incentive awarded in 2016, payable in 2019, in the amount of €1,469 thousand, vested based on the final multiplier verified over the vesting period (170%), as approved by the Board of Directors on March 14, 2019.

MANAGERS WITH STRATEGIC RESPONSIBILITIES

2019 Short-Term Incentive with deferral

Managers with strategic responsibilities earned incentives payable/awardable in 2019 based on performance achieved in 2018, in the aggregate amounts that will be disclosed in the 2020 Remuneration Report. More specifically, these incentives were related to company performance and a series of business targets, sustainability targets (i.e. safety, environmental protection, relations with stakeholders), and individual targets assigned in relation to the scope of responsibilities of the given role, in line with the provisions of Eni's Strategic Plan.

2015-2017 Deferred Monetary Incentive

Managers with strategic responsibilities earned the incentive awarded in 2016, payable in 2019, vested based on the final multiplier verified over the vesting period (170%), as approved by the Board of Directors on March 14, 2019. The total aggregate amount of such incentives will be published in 2019 Remuneration Report.

Remuneration paid in 2018

TABLE 1 - REMUNERATION PAID TO DIRECTORS, STATUTORY AUDITORS, TO THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND TO OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

The table below reports the remuneration paid to Directors, Statutory Auditors, the Chief Executive Officer and General Manager and, in aggregate form, Managers with strategic responsibilities.
The remuneration received from subsidiaries and/or associates, except that waived or paid to the company, are shown separately. All parties who filled these roles during the period are included, even if they only held office for a fraction of the year.
In particular:

- the column labelled "Fixed Remuneration" reports fixed remuneration and fixed salary from employment due for the year (on an accrual basis), gross of social security contributions and taxes to be paid by the employee. Details of the compensation are provided in the notes, and any indemnities or payments with reference to the employment relationship are indicated separately;
- the column labelled "Remuneration for participation on Committees" reports (on an accrual basis) the compensation due to Directors for participation in Committees established by the Board. In the notes, compensation for each Committee in which each Director participates is indicated separately;
- the column labelled "Variable non-equity remuneration" under the item "Bonuses and other incentives" shows the incentives paid during the year due to rights vested following the assessment and approval of related performance results by relevant corporate bodies, in accordance with that specified, in greater detail, in the Table "Monetary incentive plans for the Chief Executive Officer and General Manager and other Managers with strategic responsibilities"; the column labelled "Profit-sharing" does not show any figures since no profit- sharing mechanisms are in place;
- the column labelled "Benefits in kind" reports (on an accrual and taxability basis) the value of any fringe benefits awarded;
- the column labelled "Other remuneration" reports (on an accrual basis) any other remuneration deriving from other services provided;
- the column labelled "Total" reports the sum of the amounts of all the previous items;
- the column labelled "Fair value of equity compensation" reports the relevant fair value for the year related to the existing share plans, estimated in accordance with the international accounting standards that allocate the related cost in the vesting period;
- the column labelled "Severance indemnity for end-of-office or termination of employment" reports indemnities accrued, even if not yet paid, for terminations that occurred during the financial year, or in relation to the end of term in office and/or employment.

TABLE 1 - REMUNERATION PAID TO DIRECTORS, STATUTORY AUDITORS, THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND TO OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES (amounts in euro thousands)

							Non-equity variable remuneration						
First and last name	Note	Position	Period for which the position was held	Expiration of Office(*)	Fixed remuneration	Remuneration for participation in Committees	Bonus and other incentives	Profit sharing	Non monetary benefits	Other remuneration	Total	Fair value of equity-based remuneration	Severance indemnity for end of office or termination of employment
Board of Directors													
Emma Marcegaglia	(1)	Chairman	01.01 - 12.31	2020	500[a]						500		
Claudio Descalzi	(2)	Chief Executive Officer and General Manager	01.01 - 12.31	2020	1,600[a]		4,316[b]		17[c]		5,933	523	
Andrea Gemma	(3)	Director	01.01 - 12.31	2020	80[a]	130[b]					210		
Pietro Angelo Guindani	(4)	Director	01.01 - 12.31	2020	80[a]	85[b]					165		
Karina Litvack	(5)	Director	01.01 - 12.31	2020	80[a]	83[b]					165		
Alessandro Lorenzi	(6)	Director	01.01 - 12.31	2020	80[a]	105[b]					185		
Diva Moriani	(7)	Director	01.01 - 12.31	2020	80[a]	125[b]					205		
Fabrizio Pagani	(8)	Director	01.01 - 12.31	2020	80[a]	65[b]				50[c]	195		
Domenico Livio Trombone	(9)	Director	01.01 - 12.31	2020	80[a]	65[b]					145		
Board of Statutory Auditors													
Rosalba Casiraghi	(10)	Chairman	01.01 - 12.31	2020	80[a]						80		
Enrico Maria Bignami	(11)	Statutory auditor	01.01 - 12.31	2020	70[a]						70		
Paola Camagni	(12)	Statutory auditor	01.01 - 12.31	2020	70[a]					109[b]	179		
Andrea Parolini	(13)	Statutory auditor	01.01 - 12.31	2020	70[a]					12[b]	82		
Marco Seracini	(14)	Statutory auditor	01.01 - 12.31	2020	70[a]					109[b]	179		
Other Managers with strategic responsabilities(**)	(15)	*Remuneration in the reporting entity*			8,853		13,394		218	155	22,620	801	
		Remuneration from subsidiaries and associates											
				Total	8,853[a]		13,394[b]		218[c]	155[d]	22,620	801	
					11,873	**660**	**17,710**		**235**	**435**	**30,913**	**1,324**	

Notes

(*) The term of office expires with the Shareholders' Meeting approving the Financial Statements for the year ending December 31, 2019.

(**) Managers who were permanent members of the Company's Management Committee during the year together with the Chief Executive Officer, or who reported directly to the CEO (twenty managers).

(1) Emma Marcegaglia - Chairman of the Board of Directors

(a) The amount includes: i) the fixed remuneration of €90 thousand set by the Shareholders' Meeting on May 8, 2014 and confirmed by the Shareholders' Meeting on April 13, 2017; ii) the fixed remuneration for the delegated powers approved by the Board of Directors for the 2017-2020 term, equal to €410 thousand.

(2) Claudio Descalzi - Chief Executive Officer and General Manager

(a) The amount includes: i) the fixed remuneration for the position of Chief Executive Officer for the 2017-2020 term, coming to €600 thousand; ii) the fixed remuneration for the position of General Manager for the 2017-2020 term, coming to €1,000 thousand.

To this amounts are to be added the indemnities due for transfers, in Italy and abroad, in line with the provisions of the relevant national collective labour agreement for senior managers and the Company's complementary agreements for an amount of €20.3 thousand.

(b) The amount includes: i) annual monetary incentive and annual instalment of Short-Term Incentive of €1,997 thousand; ii) the Deferred Monetary Incentive awarded in 2015 and paid in 2018 in the amount of €1,468.8 thousand in relation to the performance targets achieved during the 2015-2017 vesting period; iii) the Long-Term Monetary Incentive of €850.5 thousand awarded in 2015 and paid in 2018 in relation to the performance targets achieved during the 2015-2017 vesting period.

(c) The amount includes the taxable value of insurance and social security benefits, supplementary pension plan and car for business and personal use.

(3) Andrea Gemma - Director

(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.

(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, and in particular €50 thousand for participating in the Control and Risk Committee; €50 thousand for the Remuneration Committee; €30 thousand for the Nomination Committee.

(4) Pietro Angelo Guindani - Director

(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.

(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, and in particular €35 thousand for participating in the Remuneration Committee; €50 thousand for the Sustainability and Scenarios Committee.

(5) Karina Litvack - Director
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, and in particular €50 thousand for participating in the Control and Risk Committee; €35 thousand for the Sustainability and Scenarios Committee.

(6) Alessandro Lorenzi - Director
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, in particular: €70 thousand for participating in the Control and Risk Committee; €35 thousand for the Remuneration Committee.

(7) Diva Moriani - Director
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, in particular: €50 thousand for participating in the Control and Risk Committee; €35 thousand for the Remuneration Committee; €40 thousand for the Nomination Committee.

(8) Fabrizio Pagani - Director
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of May 8, 2014 and confirmed by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, in particular: €35 thousand for participating in the Sustainability and Scenarios Committee; €30 thousand for the Nomination Committee.
(c) The amount corresponds to the remuneration as Chairman of the Advisory Board for the Oil & Gas sector.

(9) Domenico Livio Trombone - Director
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes the pro-rata remuneration set by the Board of Directors for participating in the Committees, in particular: €35 thousand for participating in the Sustainability and Scenarios Committee; €30 thousand for the Nomination Committee.

(10) Rosalba Casiraghi - Chairman of the Board of the Statutory Auditors
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.

(11) Enrico Maria Bignami - Statutory auditor
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.

(12) Paola Camagni - Statutory auditor
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €19.5 thousand as Chairman of the Board of Statutory Auditors of AGI SpA; €34.3 thousand as Chairman of the Board of Statutory Auditors of Mozambique Rovuma Venture SpA; €25 thousand as Statutory Auditor of Syndial; €30 thousand as Statutory Auditor of Eni Angola SpA.

(13) Andrea Parolini - Statutory auditor
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €12 thousand as Statutory Auditor of Ing. Luigi Conti Vecchi SpA.

(14) Marco Seracini - Statutory auditor
(a) The amount corresponds to the annual fixed remuneration set by the Shareholders' Meeting of April 13, 2017.
(b) The amount includes remuneration for serving as Statutory Auditor on the Boards of subsidiaries or associated companies and in particular: €27 thousand as Chairman of the Board of Statutory Auditors of LNG Shipping SpA; €27 thousand as Chairman of the Board of Statutory Auditors of Ing. Luigi Conti Vecchi; €30 thousand as Statutory Auditor of Eni Fuel SpA; pro-rated amount of €3.8 thousand as Statutory Auditor of Eni Adfin SpA; pro-rated amount €21.3 thousand as Statutory Auditor of TTPC SpA.

(15) Other Managers with strategic responsibilities
(a) The amount of €8,853 thousand for Gross Annual Salary is supplemented by the indemnities owed for transfers, in Italy and abroad, in line with the provisions of the relevant national collective labour agreement and with the Company's additional agreements, as well as other indemnities related to employment for a total of €201 thousand.
(b) The amount includes the payment of €6,124 thousand related to the deferred and long-term monetary incentives awarded in 2015 and paid in 2018 for performance targets achieved in the 2015-2017 vesting period.
(c) The amount includes the taxable value of insurance and welfare coverage, complementary pensions and the car for business and personal use.
(d) Amounts due to for the positions held by Managers with strategic responsibilities in the Supervisory Body established under the Company's Model 231 and the Manager responsible for the preparation of the Company's financial statements.

TABLE 2 - MONETARY INCENTIVE PLANS FOR THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

The table below reports, by name, the variable monetary incentives, both Short and Long-Term, envisaged for the Chief Executive Officer and General Manager and, at an aggregate level, other Managers with strategic responsibilities (including all individuals who filled these roles during the period, even if for only a fraction of the year).
The column labelled "Bonus for the year" details:
- under the item "payable/paid", the short-term variable incentive award paid during the year based on verification by relevant Company bodies that performance met the objectives defined for the previous year;
- under the item "deferred", the amount of the base incentive awarded during the year in line with the Monetary Incentive Plan with deferral;
- under the item "deferral period", the duration of the vesting period for the deferred incentive awarded in the year.

The column labelled "Bonus for previous years" details:
- under the item "no longer payable", the Long-Term incentive awards no longer payable in relation to verified performance conditions for the vesting period or incentives that expired due to events relating to employment relationships as envisaged in the Plan Rules;
- under the item "payable/paid", the Long-Term incentives paid during the year, accruing on the basis of verification of the performance conditions for the vesting period, or the incentive amounts paid due to events relating to employment relationships as envisaged in the Plan Rules;
- under the item "still deferred", incentives awarded in previous years that have not yet vested, in line with previous Long-Term incentive plans.

The column labelled "Other Bonuses" details incentives paid on a one-off extraordinary basis related to the achievement of particularly important results or projects during the year.
The total of the amounts under the item "payable/paid" in the columns "Bonus for the year", "Bonus for previous years" and "Other Bonuses" is the same as that indicated in the "Bonuses and other incentives" column in Table 1.

TABLE 2 – MONETARY INCENTIVE PLANS FOR THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES (thousands of euros)

			Bonus for the year			Bonus for previous years			
First name and surname	Position	Plan	payable/ paid	deferred	deferred period	no longer payable	payable/ paid[1]	still deferred	Other bonuses
Claudio Descalzi	Chief Executive Officer and General Manager	2018 Annual Monetary Incentive Plan and Short-Term Incentive Plan[2] BoD March 15, 2018	1,997						
		2018 Short-Term Incentive Plan – Deferred portion BoD March 15, 2018		811	3 years				
		2017 Deferred Monetary Incentive Plan BoD February 28, 2017						864	
		2016 Deferred Monetary Incentive Plan BoD March 17, 2016						864	
		2016 Long-Term Monetary Incentive Plan BoD September 15, 2016						1,350	
		2015 Deferred Monetary Incentive Plan Award: BoD March 12, 2015 Payment: BoD March 15, 2018					1,469		
		2015 Long-Term Monetary Incentive Plan Award: BoD September 17, 2015 Payment: BoD May 24, 2018				500[4]	850		
Total			**1,997**	**811**		**500**	**2,319**	**3,078**	
Other Managers with strategic responsibilities[3]		2018 Short-Term Incentive Plan - Paid portion BoD March 15, 2018	7,270						
		2018 Short-Term Incentive Plan - Deferred portion BoD March 15, 2018		3,198	3 years				
		2017 Deferred Monetary Incentive Plan BoD February 28, 2017						3,615	
		2016 Deferred Monetary Incentive Plan BoD March 17, 2016						3,033	
		2016 Long-Term Monetary Incentive Plan BoD September 15, 2016						3,233	
		2015 Deferred Monetary Incentive Plan Award: BoD March 12, 2015 Payment: BoD March 15, 2018					4,308		
		2015 Long-Term Monetary Incentive Plan Award: BoD September 17, 2015 Payment: BoD May 24, 2018				1,139[4]	1,816		
Total			**7,270**	**3,198**		**1,139**	**6,124**	**9,881**	
			9,267	**4,009**		**1,639**	**8,443**	**12,959**	

(1) Payment relating to the deferred monetary incentive and the long-term monetary incentive awarded in 2015.

(2) Includes:
- pro-rated Annual Monetary Incentive 2018 (€491 thousand);
- pro-rated Short-Term Incentive 2018 (€1,506 thousand).

(3) Managers who were permanent members of the Company's Management Committee during the year, together with the Chief Executive Officer and who reported directly to the CEO (twenty managers).

(4) Amount no longer payable, equal to the difference between the incentive awarded in 2015 and that paid in 2018.

TABLE 3 – INCENTIVE PLANS BASED ON FINANCIAL INSTRUMENTS OTHER THAN STOCK OPTIONS FOR THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND FOR OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

The table below shows, for the equity-based incentive plan, the shares awarded to the Chief Executive Officer and General Manager and the aggregate numbers awarded to the other Managers with strategic responsibilities (including all individuals who covered such positions for any period of time during the year).
In particular:

- the column "Financial instruments awarded in previous years and not vested during the year" shows the type, number and vesting period of any financial instruments awarded in previous years and not yet vested;
- the column "Financial instruments awarded during the year" shows the type, number, total fair value, vesting period, award date, and market price on that date for financial instruments awarded during the year;
- the column "Financial instruments vested during the year and not granted" shows the type and number of any financial instruments awarded and no longer grantable based on verification of performance during the vesting period, or of any financial instruments awarded and not grantable due to termination of employment as envisaged by the rules of the plans;
- the column "Financial instruments vested during the year and grantable" shows the type, number and value on the vesting date of any financial instruments awarded and vested during the year and grantable based on the verification of performance during the vesting period, or the amounts due to events relating to employment relationship as envisaged by the rules of the plans;
- the column "Financial instruments for the year" shows the fair value of the financial instruments awarded and still in existence solely for the portion related to the year, which is also shown in Table 1 in the column "Fair value of equity-based remuneration".

TABLE 3 - INCENTIVE PLANS BASED ON FINANCIAL INSTRUMENTS OTHER THAN STOCK OPTIONS FOR THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND FOR OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

			Financial instruments awarded in previous years and not vested during the year		Financial instruments awarded during the year						Financial instruments vested during the year and not granted	Financial instruments vested during the year and grantable		Financial instruments for the year
First name and surname	Position	Plan	Number of Eni shares	Vesting period	Number of Eni shares	Fair value at award date (thousands of euros)	Vesting period	Award date	Market price on award date (euro)	Number of Eni shares	Number of Eni shares	Value at date of vesting	Fair value (thousands of euros)
Claudio Descalzi	Chief Executive Officer and General Manager	2018 Equity-Based Long-Term Incentive Plan BoD October 25, 2018			149,722	1,757	3 years	25/10/2018	14.97				49
		2017 Equity-Based Long-term Incentive Plan BoD October 26, 2017	177,968	3 years									474
Total			**177,968**		**149,722**	**1,757**							**523**
Other Managers with strategic responsibilities[1]		2018 Equity-Based Long-Term Incentive Plan BoD October 25, 2018			235,191	2,759	3 years	30/11/2018	14.25				77
		2017 Equity-Based Long-term Incentive Plan BoD October 26, 2017	271,884	3 years									724
Total			**271,884**		**235,191**	**2,759**							**801**
			449,852		**384,913**	**4,516**							**1,324**

(1) Managers who were permanent members of the Company's Management Committee during the year, together with the Chief Executive Officer and who reported directly to the CEO (twenty managers).

Shareholdings held

The table below reports, under Article 84-quater, fourth paragraph, of the Consob Issuers Regulation, the shareholdings in Eni SpA and its subsidiaries that are held by Directors, Statutory Auditors, and other Managers with strategic responsibilities, as well as by their spouses from whom they are not legally separated, and their children under eighteen years of age, directly or through subsidiaries, trust companies, or intermediaries, as recorded in the register of shareholders, communications received and other information sources. The table includes all parties who meet this description for all or part of the reporting period.
The number of shares (all "ordinary") is indicated, for each company held, by name, for Directors, Statutory Auditors, and, at an aggregate level, for the other Managers with strategic responsibilities. The individuals indicated hold title to the shareholdings.

TABLE 4 - SHAREHOLDINGS HELD BY DIRECTORS, STATUTORY AUDITORS, THE CHIEF EXECUTIVE OFFICER AND GENERAL MANAGER AND OTHER MANAGERS WITH STRATEGIC RESPONSIBILITIES

First name and surname	Position	Affiliated company	Number of shares held as at 31.12.2017	Number of shares purchased	Number of shares sold	Number of shares held as at 31.12.2018
Board of Directors						
Emma Marcegaglia	Chairman	Eni SpA	34,270			34,270
		Eni SpA[1]	45,000			45,000
		Eni SpA[2]	7,740			7,740
Claudio Descalzi	Chief Executive Officer and General Manager	Eni SpA	39,455			39,455
Board of Statutory Auditors						
			-	-	-	-
Other managers with strategic responsibilities[3]		Eni SpA	177,079	2,860	720	179,219

(1) Bare ownership.
(2) Asset management.
(3) Managers who were permanent members of the Company's Management Committee during the year, together with the Chief Executive Officer and who reported directly to the CEO (twenty managers).

Annex under Article 84-bis of Consob Issuer Regulation – 2018 Implementation of the 2017-2019 Long-Term Share Incentive Plan

With reference to the 2017-2019 Long-Term Share Incentive Plan approved by the ordinary Shareholders' Meeting on April 13, 2017, subject to the conditions and purposes set out in the Information Document available on the website, the following table shows details of the 2018 Plan award, in accordance with Art.84-bis (Annex 3A, schedule 7) of the Consob Issuer Regulation.

TABLE NO. 1 OF SCHEDULE 7 OF ANNEX 3A OF REGULATION NO. 11971/1999

REMUNERATION PLANS BASED ON FINANCIAL INSTRUMENTS

		FRAME 1						
		FINANCIAL INSTRUMENTS OTHER THAN STOCK OPTIONS						
		Section 2 Newly instruments awarded based on the decision of the competent body in charge of the implementation of the resolution of the Shareholders' Meeting						
First name and surname or category	Position (to be specified only for individuals listed by name)	Date of shareholders' resolution	Type of financial instruments	Number of financial instruments	Award date	Purchase price of the instruments	Market price on award date (euro)	Vesting period
Claudio Descalzi	CEO and GM of Eni SpA	April 13, 2017	Eni shares	149,722[1]	25/10/18	n.a.	14.97	3 years
Nicolò Aggogeri	Managing Director Agip Caspian Sea BV	April 13, 2017	Eni shares	1,809	30/11/18	n.a.	14.25	3 years
Ignazio Arces	CEO Raffineria di Gela SpA	April 13, 2017	Eni shares	1,466	30/11/18	n.a.	14.25	3 years
Abdulmonem Arifi	Managing Director Eni North Africa BV	April 13, 2017	Eni shares	5,646	30/11/18	n.a.	14.25	3 years
Massimo Bechi	CEP Eni Deutschland GmbH	April 13, 2017	Eni shares	2,339	30/11/18	n.a.	14.25	3 years
Mario Bello	Managing Director Eni Algeria Production BV	April 13, 2017	Eni shares	3,088	30/11/18	n.a.	14.25	3 years
Claudio Brega	Amministratore Delegato Eniservizi SpA	April 13, 2017	Eni shares	6,519	30/11/18	n.a.	14.25	3 years
Paolo Campelli	Managing Director Eni Mozambique Engineering Limited	April 13, 2017	Eni shares	2,932	30/11/18	n.a.	14.25	3 years
Fabio Cavanna	Managing Director IEOC Production BV	April 13, 2017	Eni shares	3,213	30/11/18	n.a.	14.25	3 years
Andrea Cecchinato	Chairman and CEO Ing. Luigi Conti Vecchi SpA	April 13, 2017	Eni shares	1,372	30/11/18	n.a.	14.25	3 years
Alberto Chiarini	CEO Eni gas e luce SpA	April 13, 2017	Eni shares	12,477	30/11/18	n.a.	14.25	3 years
Marco Coccagna	CEO Eni Corporate University SpA	April 13, 2017	Eni shares	4,149	30/11/18	n.a.	14.25	3 years
Carmine De Lorenzo	Managing Director Eni Venezuela BV	April 13, 2017	Eni shares	3,431	30/11/18	n.a.	14.25	3 years
Daniel Fava	Directeur General Eni Gas & Power France SA	April 13, 2017	Eni shares	3,743	30/11/18	n.a.	14.25	3 years
Daniele Ferrari	CEO Versalis SpA	April 13, 2017	Eni shares	13,725	30/11/18	n.a.	14.25	3 years
Lorenzo Fiorillo	Managing Director Nigerian Agip Oil Company Limited	April 13, 2017	Eni shares	3,525	30/11/18	n.a.	14.25	3 years
Ernesto Formichella	Managing Director Banque Eni SA	April 13, 2017	Eni shares	3,275	30/11/18	n.a.	14.25	3 years
Gabriele Franceschini	President and Chief Executive Officer Eni US Operating Co. Inc.	April 13, 2017	Eni shares	3,462	30/11/18	n.a.	14.25	3 years
Alessandro Gelmetti	Managing Director Eni Myanmar BV	April 13, 2017	Eni shares	2,090	30/11/18	n.a.	14.25	3 years
Andrea Giaccardo	Managing Director Eni Angola Production BV	April 13, 2017	Eni shares	1,747	30/11/18	n.a.	14.25	3 years
Philip Duncan Hemmens	Managing Director EniNorge AS	April 13, 2017	Eni shares	3,578	30/11/18	n.a.	14.25	3 years
Massimo Maria Insulla	Managing Director Eni Iraq BV	April 13, 2017	Eni shares	3,712	30/11/18	n.a.	14.25	3 years
Salvatore Ippolito	CEO Agenzia Giornalistica Italia SpA	April 13, 2017	Eni shares	2,901	30/11/18	n.a.	14.25	3 years
Giuseppe La Scola	Chairman & General Manager Versalis Pacific Trading (Shanghai) CO Ltd	April 13, 2017	Eni shares	2,870	30/11/18	n.a.	14.25	3 years
Vincenzo Larocca	Managing Director Syndial SpA	April 13, 2017	Eni shares	7,611	30/11/18	n.a.	14.25	3 years

(1) Number of shares assigned with resolution of the Shareholders' Meeting of October 25, 2018.

TABLE NO. 1 OF SCHEDULE 7 OF ANNEX 3A OF REGULATION NO. 11971/1999
REMUNERATION PLANS BASED ON FINANCIAL INSTRUMENTS

First name and surname or category	Position	FRAME 1						
		FINANCIAL INSTRUMENTS OTHER THAN STOCK OPTIONS						
		Section 2 Newly instruments awarded based on the decision of the competent body in charge of the implementation of the resolution of the Shareholders' Meeting						
	(to be specified only for individuals listed by name)	Date of shareholders' resolution	Type of financial instruments	Number of financial instruments	Award date	Purchase price of the instruments	Market price on award date (euro)	Vesting period
Angelo Ligrone	Managing Director Eni Pakistan Limited	April 13, 2017	Eni shares	2,589	30/11/18	n.a.	14.25	3 years
Franco Magnani	Managing Director Oil Eni Trading & Shipping SpA	April 13, 2017	Eni shares	9,420	30/11/18	n.a.	14.25	3 years
Carmine Masullo	President and Chief Executive Officer Versalis International SA	April 13, 2017	Eni shares	4,055	30/11/18	n.a.	14.25	3 years
Giuseppe Moscato	Directeur General EniTunisia BV	April 13, 2017	Eni shares	3,369	30/11/18	n.a.	14.25	3 years
Biagio Pietraroia	Managing Director Agip Karachaganak BV	April 13, 2017	Eni shares	3,275	30/11/18	n.a.	14.25	3 years
Stefano Quartullo	CEO Eni France Sàrl	April 13, 2017	Eni shares	2,152	30/11/18	n.a.	14.25	3 years
Federico Regola	Managing Director Gas Supply Company of Thessaloniki-Thessalia S.A. - ZENITH GAS & LIGHT	April 13, 2017	Eni shares	3,026	30/11/18	n.a.	14.25	3 years
Francesca Rinaldi	Managing Director Eni UK Limited	April 13, 2017	Eni shares	1,622	30/11/18	n.a.	14.25	3 years
Damian Robinson	President & CEO Eni Trading & Shipping Inc	April 13, 2017	Eni shares	2,701	30/11/18	n.a.	14.25	3 years
Marco Rotondi	Directeur General Eni Congo SA	April 13, 2017	Eni shares	1,747	30/11/18	n.a.	14.25	3 years
Giancarlo Ruiu	Managing Director Eni Ghana Exploration and Production Limited	April 13, 2017	Eni shares	1,747	30/11/18	n.a.	14.25	3 years
Mauro Russo	Chairman and CEO Eni Iberia SLU	April 13, 2017	Eni shares	2,589	30/11/18	n.a.	14.25	3 years
Loris Tealdi	Managing Director Eni Abu Dhabi BV	April 13, 2017	Eni shares	3,119	30/11/18	n.a.	14.25	3 years
Andrea Tomasino	Chairman and Managing Director Versalis UK Ltd	April 13, 2017	Eni shares	1,372	30/11/18	n.a.	14.25	3 years
Enrico Trovato	Managing Director Eni Turkmenistan Limited	April 13, 2017	Eni shares	1,778	30/11/18	n.a.	14.25	3 years
Luciano Maria Vasques	Chairman and CEO EniProgetti SpA	April 13, 2017	Eni shares	4,180	30/11/18	n.a.	14.25	3 years
Umberto Vergine	Managing Director Eni International BV	April 13, 2017	Eni shares	14,068	30/11/18	n.a.	14.25	3 years
Claudia Vignati	Managing Director Eni Finance International SA	April 13, 2017	Eni shares	2,433	30/11/18	n.a.	14.25	3 years
Marco Volpati	Managing Director Eni International Resources Ltd	April 13, 2017	Eni shares	2,683	30/11/18	n.a.	14.25	3 years
Paolo Zuccarini	Chairman Versalis France SAS	April 13, 2017	Eni shares	3,119	30/11/18	n.a.	14.25	3 years
Other Eni Managers with strategic responsibilities[2]	16 managers	April 13, 2017	Eni shares	201,378	30/11/18	n.a.	14.25	3 years
Other managers	315 managers	April 13, 2017	Eni shares	995,151	30/11/18	n.a.	14.25	3 years

(2) Other managers who, at time of assignment and together with the Chief Executive Officer, were permanent members of the Company's Management Committee or reported directly to the CEO.

Exhibit 15.a (ii)

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

March 8, 2019

Eni S.p.A.
Pietro G. Consonni
Vice President, Reserves
Via Emilia 1
20097 San Donato Milanese
Milano, Italy

Dear Mr. Consonni:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2018, of the net proved oil, condensate, liquefied petroleum gas (LPG), and gas reserves of certain properties in Africa, Australia, Central America, and Europe in which Eni S.p.A. (Eni) has represented it holds an interest. This evaluation was completed on March 8, 2019. Eni has represented that these properties account for 14 percent, on a net equivalent barrel basis, of Eni's net proved reserves as of December 31, 2018, 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 Securities and Exchange Commission (SEC) of the United States. It is our opinion that the procedures and methodologies employed by Eni for the preparation of its proved reserves estimates as of December 31, 2018, 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, 2018, 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, 2018. 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 of the properties 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 (Revision as of February 19, 2007).” 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.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure 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. In these instances, an analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

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 or to the limit of production licenses as appropriate.

In certain cases, elements of the reserves estimates incorporated information based on analogy with similar reservoirs for which more complete data were available.

Data provided by Eni from wells drilled through December 31, 2018, 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 through June 31, 2018 for certain properties and as late as
September 30, 2018, for other properties. Where, applicable, estimated cumulative production, as of December 31, 2018, 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 those 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 estimates included in this report are expressed in millions of barrels (10^6bbl). In these estimates, 1 barrel equals 42 United States gallons.

Gas quantities estimated herein are expressed as marketable gas. Marketable gas is defined as the total gas potentially to be produced from the reservoir after reduction for shrinkage resulting from field separation, processing, flare, and other losses but before reduction for gas consumed in operations (fuel). Gas reserves estimated herein 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 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 are 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 5,458 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Eni.

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 provided all pricing information, and it has represented that the provided 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 arrangements. A Brent oil price of U.S.$71.43 per barrel was the resulting reference price. Where appropriate, Eni supplied differentials by field to the relevant reference price, and the prices were held constant thereafter. The volume-weighted average oil, condensate, and LPG prices used in this report are presented below, expressed in United States dollars per barrel (U.S.$/bbl):

	Oil Price (U.S.$/bbl)	Condensate and LPG Price (U.S.$/bbl)
Africa	66.83	68.27
Australia	N/A	58.31
Central America	70.07	N/A
Europe	70.01	N/A
Average for Total	**67.31**	**66.54**

Note: “N/A” is Not Applicable.

Gas Prices

Eni has represented that the provided 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 arrangements. A significant quantity of the gas sold by Eni is subject to contract prices, and the range of such prices is varied. A reference price is the United Kingdom National Balancing Point Index, which was U.S.$5.72 per thousand cubic feet. Where appropriate, Eni supplied differentials by field to the relevant reference price and the prices were held constant thereafter. The volume-weighted average gas prices used in this report are presented below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Gas Price (U.S.$/$10^3$ft^3)
Africa	5.67
Australia	3.39
Central America	3.63
Europe	7.98
Average for Total	**5.41**

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 Financial Accounting Standards Board 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, Australia, Central America, and Europe were based on the definitions of proved reserves of the SEC. Eni has represented that its estimates of the net proved reserves attributable to these properties, which represent 14 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, 2018		
	Oil, Condensate, and LPG (10^6bbl)	**Marketable Gas (10^9ft^3)**	**Oil Equivalent (10^6boe)**
Properties evaluated by DeGolyer and MacNaughton			
Total Proved	**486**	**2,701**	**981**

Note: Marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,458 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, 2018, 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,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Regnald A. Boles

[Seal]

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 8, 2019, 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; and that I have in excess of 35 years of experience in oil and gas reservoir studies and evaluations.

SIGNED: March 8, 2019

/s/ Regnald A. Boles

[Seal]

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

Exhibit 15.a (iii)

Eni S.p.A.

Estimated

Future Reserves and Income

Attributable to Certain

Interests

SEC Parameters

As of

December 31, 2018

/s/ Herman G. Acuña

Herman G. Acuña, P.E.
TBPE License No. 92254
Managing Senior Vice President-International

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

February 20, 2019

Eni S.p.A
Mr. Pietro G. Consonni
Vice President Reserves
Via Emilia 1
20097 San Donato Milanese
Milano, Italy

Dear Mr. Consonni,

At the request of Eni S.p.A. (Eni), Ryder Scott Company, L.P (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as prepared by Eni's engineering and geological staff as of December 31, 2018 based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on February 13, 2019 and presented herein, was prepared for public disclosure by Eni in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. Eni has indicated that the proved net reserves attributable to the properties that we reviewed account for 10 percent of their total net proved remaining hydrocarbon reserves. The subject properties are located in the following two geographic locations:

- Africa
- Americas

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves and/or Reserves Information prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities and/or Reserves Information." Reserves Information may consist of various estimates pertaining to the extent and value of petroleum properties.

Based on our review, including the data, technical processes and interpretations presented by Eni, it is our opinion that the overall procedures and methodologies utilized by Eni in preparing their estimates of the proved reserves as of December 31, 2018 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by Eni are, in the aggregate, reasonable within 5 percent of Ryder Scott's estimates which is less than the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards. Ryder Scott found the processes and controls used by Eni in their estimation of proved reserves to be effective and, in the aggregate, we found no bias in the utilization and analysis of data in estimates for these properties.

SUITE 800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799 FAX (403) 262-2790
621 17TH STREET, SUITE 1550 DENVER, COLORADO 80293-1501 TEL (303) 623-9147 FAX (303) 623-4258

The conclusions discussed in this report are related to hydrocarbon prices. Eni has informed us that in preparation of their reserves and income projections, as of December 31, 2018, they used average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations; therefore, volumes of reserves actually recovered may differ significantly from the estimated quantities audited by Ryder Scott.

Reserves Included in This Report

In our opinion, the proved reserves discussed herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various proved reserves status categories are defined under the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The audited proved gas volumes include gas consumed in operations as reserves. Non-hydrocarbon or inert gas volumes have been excluded from the reserves reported herein.

Reserves are those estimated remaining quantities of petroleum that are anticipated to be economically producible, as of a given date, from known accumulations under defined conditions. All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Eni’s request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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.” The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.”

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

The proved reserves discussed herein are limited to the period prior to expiration of current contracts providing the legal rights to produce, or a revenue interest in such production, unless evidence indicates that contract renewal is reasonably certain. Furthermore, properties in the different countries may be subjected to substantially varying contractual fiscal terms that affect the net revenue to Eni for the production of these volumes. The prices and economic return received for these net volumes can vary materially based on the terms of these contracts. Therefore, when applicable, Ryder Scott reviewed the fiscal terms of such contracts and discussed with Eni the net economic benefit attributed to such operations for the determination of the net hydrocarbon volumes and income thereof. Ryder Scott has not conducted an exhaustive audit or verification of such contractual information. Neither our review of such contractual information nor our acceptance of Eni's representations regarding such contractual information should be construed as a legal opinion on this matter.

Ryder Scott did not evaluate the country and geopolitical risks in the countries where Eni operates or has interests. Eni's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms of various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves audited herein were based upon a detailed review of the properties in which Eni owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

One hundred percent of the proved reserves, prepared by Eni, for the properties that we reviewed were estimated by performance methods, analogy methods, the volumetric method, or a combination of performance and volumetric methods. These performance methods include, but may not be limited to, decline curve analysis, reservoir simulation and analogy which utilized extrapolations of historical production and pressure data available through September 2018 in those cases where such data were considered to be definitive. The data utilized in this analysis were supplied to Ryder Scott by Eni and were considered sufficient for the purpose thereof. As part of our investigations, volumetric estimates were incorporated where we considered it appropriate to verify volumetrically the performance methods described above. The volumetric analysis utilized pertinent well and seismic data supplied to Ryder Scott by Eni that were available through September 2018. The data utilized from the well and seismic data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

Eni has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Eni with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Eni. We consider the factual data furnished to us by Eni to be appropriate and sufficient for the purpose of our review of Eni's estimates of reserves.

In summary, we consider the assumptions, data, methods and analytical procedures used by Eni and as reviewed by us to be appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Future Production Rates

For wells currently on production, Eni's forecasts of future production rates are based on historical performance. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by Eni to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Eni. Wells or locations that are not currently producing may start producing earlier or later than anticipated in Eni's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by Eni relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Eni furnished us with the above mentioned average prices in effect on December 31, 2018. Eni has assured us that these initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. The average dated Brent oil price of $71.54/bbl was used by Eni. Eni also provided us with the gas prices based on their gas sales agreements. All gas prices shown below are in dollars per thousand cubic meters ($\$/km^3$). The average realized prices provided by Eni and used in our evaluation are as follows:

Geographic Area	Product	Average Proved Realized Prices	
Africa	Oil	$	71.62/bbl
	Condensate	$	48.89/bbl
	Gas	$	147.68/km3
Americas	Oil	$	63.35/bbl
	Condensate	$	68.80/bbl

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Eni. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Eni to determine these differentials.

Costs

Operating costs used in our evaluation were based on the operating expense reports of Eni and include only those costs directly applicable to the evaluated assets. The operating costs include a portion of general and administrative costs allocated directly to the leases, contract areas and wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Eni. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the assets.

Development costs were furnished to us by Eni and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by Eni were accepted without independent verification.

The proved developed and undeveloped reserves in this report have been incorporated herein in accordance with Eni's plans to develop these reserves as of December 31, 2018. The implementation of Eni's development plans as presented to us and incorporated herein is subject to the approval process adopted by Eni's management. As the result of our inquires during the course of preparing this report, Eni has informed us that the development activities included herein have been subjected to and received the internal approvals required by Eni's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Eni. Additionally, Eni has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2018, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Eni were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Eni. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Eni.

We have provided Eni with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Eni and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L. P.
TBPE Firm Registration No. F-1580

/s/ Herman G. Acuña

Herman G. Acuna, P.E.
TBPE License No. 92254
Managing Senior Vice President – International

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Herman G. Acuña was the primary technical person responsible for overseeing the independent estimation of the reserves, future production and income to render the audit conclusions of the report.

Mr. Acuña, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 1997, is a Managing Senior International Vice President and Board Member. He serves as an Engineering Group Coordinator responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Acuña served in a number of engineering positions with Exxon. For more information regarding Mr. Acuña's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com.

Mr. Acuña earned a Bachelor (Cum Laude) and a Masters (Magna Cum Laude) of Science degree in Petroleum Engineering from The University of Tulsa in 1987 and 1989 respectively. He is a registered Professional Engineer in the State of Texas, a member of the Association of International Petroleum Negotiators (AIPN) and the Society of Petroleum Engineers (SPE).

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Acuña fulfills. Mr. Acuña has attended formalized training and conferences including dedicated to the subject of the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Acuña has recently taught various company reserves evaluation schools in Argentina, China, Denmark, Spain and the U.S.A. Mr. Acuña has participated in various capacities in reserves conferences such as being a panelist at Trinidad and Tobago's Petroleum Conference, delivering the reserves evaluation seminar during IAPG convention in Mendoza, Argentina and chairing the first Reserves Evaluation Conference in the Middle East in Dubai, U.A.E.

Based on his educational background, professional training and over 20 years of practical experience in petroleum engineering and the estimation and evaluation of petroleum reserves, Mr. Acuña has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves 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.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals that are open at the time of the estimate but which have not yet started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 15.a(iv)

Eni.S.p.A
Mr. Pietro Giuseppe Consonni
Via Emilia 1
20097 San Donato Milanese
Milan, Italy

22nd of February 2019

Dear Mr.Consonni

In accordance with its agreement with Eni S.p.A (Eni or "the Client"), SGS Nederland B.V. , its Subsurface consultancy division (hereinafter "SGS") has conducted an independent Proved reserves audit (hereinafter "the Audit") of the proved reserves as of December 31st, 2018 estimated by Eni on a property located in the Sub-Saharan Africa Geographical Area of which ENI has an interest subject to the terms of an Exploration and Production Concession Contract (EPCC). This third party report was completed on February 20th, 2019 and, on Eni's request, is intended for public disclosure by Eni in filings to the United States Securities and Exchange Commission (SEC).

Proved Reserves estimates are based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14th, 2009 in the Federal Register (SEC regulations).

The Proved reserves included herein are expressed as net Eni reserves and are based on the signed agreements with the government, the Sales and Purchases Agreement (SPA) signed with the buyer and using existing economic conditions.

Eni has advised that the net proved reserves attributable to the property reviewed by SGS represent 2% of Eni's total proved net reserves, as of the 31st of December 2018. However, SGS is not in a position to confirm this statement as it was not requested to audit all other assets comprising Eni's total proved reserves.

The Audit has been carried out following the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information", approved by the SPE Board in June 2001 with revisions as of February 19th, 2007", using Eni's proved reserves estimates and other technical and commercial information provided by Eni to SGS up to December 31st, 2018.

Based on SGS' review, including the data, methodology and interpretations provided by Eni, it is SGS' opinion that the overall procedures, methodologies and thoroughness used by Eni in the proved reserves estimation process are appropriate and that a thorough approach has been followed, using methods considered sound in the determination of the net proved reserves. The quality of the data relied upon and the depth and thoroughness of the reserves estimation process as well as the classification and categorization of the proved reserves by Eni are appropriate and conform with the current regulations in part 210, Rule 4-10(a) Regulation S-X of the United States Securities and Exchange Commission (see Appendix 1).

The net proved reserves estimated by SGS for the property being audited are, on the aggregate, reasonable and within 4.9% of Eni's net proved reserves estimates.

The Audit conclusions presented in the SGS report are based on constant average hydrocarbon prices as per SEC regulations and on the contractual price formulae determined by the signed Sales and Purchases Agreement (SPA). Proved reserves are the "as sold" volumes, as specified in the signed SPA, and therefore no uncontracted volumes have been included in the proved reserves estimated by SGS. Where appropriate, prices reflect the signed SPA terms and conditions. Eni's share of gas volumes consumed in own operations has been included as proved reserves. To the best of its knowledge, SGS is not aware of any global-, regional- or country- regulations that could impact the envisaged ongoing development.

1. METHODOLOGY, PROCEDURES, UNCERTAINTIES AND ASSUMPTIONS, PRICES AND COSTS

1 METHODOLOGY, PROCEDURES, UNCERTAINTIES AND ASSUMPTIONS

Technical and commercial information provided to SGS on this property consisted of engineering, geoscience and commercial data, including but not limited to well logs, well test data, core data, core analysis, seismic data, pressure data, sedimentological and geological modelling. The estimation of reserves was carried out using appropriate principles and techniques commonly used and accepted by the Oil and Gas industry, including but not limited to volumetric estimates, material balance, analogs, approval documents to establish the project's maturity and contractual terms and conditions that allowed the estimation, to the economic limit, of the proved reserves. Furthermore, the process engineering from wellhead to the terminal point of sales has been reviewed and found sound and accurate. The techniques used rely on engineering and geo-scientific interpretation and judgment; hence the resources included in this evaluation are estimates only and should not be construed to be exact quantities. It should be recognized that such estimates of hydrocarbon resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria, sales volumes or regulatory requirements. Property descriptions, details of interests held, well data, and commercial terms and conditions including fiscal, as obtained from Eni or public sources, were accepted as represented.

As part of this study SGS has audited the static models made available by Eni and has validated the key uncertainties and their range of uncertainty. The sensitivity analysis carried out by Eni using the identified uncertainties to quantify their individual impact, was also audited by SGS who found the approach and methodology sound. The reviewed work demonstrated that the key subsurface uncertainties are in the Gas Initially In Place (GIIP) driven by structural uncertainty away from the existing wells, reservoir properties and by the hydrocarbon volumes below the Lowest Known Hydrocarbons (LKH) not included in the evaluation of the proved reserves. Sensitivity analysis also indicated that the impact of the dynamic uncertainties is considered to be insignificant, given the degree of available local and regional information. Multiple reservoir realizations were used to generate a cumulative frequency distribution of the Gas Initially in Place. In its Audit, SGS has selected a deterministic reservoir model realization associated to the Lowest Known Hydrocarbon (LKH), close to the P90 static GIIP volume, which represents the Low GIIP estimate.

As part of the Audit, SGS developed production forecasts of wellhead gas using a material balance model and Eni's approved Field Development Plan, using the low GIIP as determined above and conservative dynamic parameters. The wellhead gas production profile was subsequently translated (using available process engineering tools) into volumes required to operate the facilities (fuel gas) from the wellhead to the terminal point, volumes of Liquefied Natural Gas available for sale, at the terminal point, as per contractual terms in the signed SPA, as well as the profile of condensate sales also at the terminal point. The resulting sales of Liquefied Natural Gas and condensate, and fuel gas profiles, up to the termination of the SPA contract, were properly validated and processed through the economic model using existing economic conditions, the SPA commercial terms and conditions and Eni's net interest in the property with the terms and conditions of the EPCC, resulting in the net proved reserves of gas and liquids as estimated by SGS.

Comparison of the aggregate SGS' net proved reserves estimates were found to be within 4.9% of ENI's estimates, which showed the reasonableness of Eni's proved reserves figures.

The project was sanctioned by Eni (at the appropriate local, regional and corporate level) and its partners during 2017. Construction began in July 2017 and is expected to be completed before 2022, with first gas expected in mid-2022. Eni has indicated that they are not aware of any legal, regulatory, political or economic obstacles that would impact the completion of this project as planned.

SGS has carried out the procedures needed to provide an opinion of the appropriateness of the methodologies, the adequacy and quality of the data and the depth and thoroughness of the reserves estimation process used by Eni and the classification and categorization of the reserves appropriate to the SEC regulations. As stated above, the reasonableness of ENI's proved reserves estimates has also been assessed. SGS has made every effort to ensure that the interpretations presented herein are accurate and reliable in accordance with SEC regulations, good industry practice and its own quality management procedures.

SGS has not made any field examination of the property, and no consideration was given in this report to potential environmental liabilities that may exist. As described above, several uncertainties associated to the estimation of oil and gas reserves exist, as subsurface accumulations of oil and gas cannot be measured in an exact manner. Reserves estimates should only be regarded as estimates that may change as production performance and new information become available. However, in this case the proved reserves estimates are capped by the presently signed SPA.

1.1.1 HYDROCARBON PRICES

The hydrocarbon prices applied in this reserves audit have been provided by ENI and the revenue has been calculated as per agreed SPA terms and conditions, where the Liquefied Natural Gas price at the terminal point is linked to Brent and the Japan Korean Marker (JKM) netback, using as input existing economic conditions of prices and costs. The reference price applied is defined as the average price during the 12-month period prior to the ending date of the period covered by this report, determined as an unweighted arithmetic average of the first-day- of-the month price for each month prior to the reference date. The price differential (with Brent) for the condensate has been provided by ENI and used in SGS' evaluation. The reference date for the audited reserves is December 31st, 2018.

The table below provides an overview of the prices used in the economic evaluation:

GEOGRAPHIC AREA	PRODUCT	PRICE REFERENCE	2018 AVERAGE PRICES
Sub Saharan Africa	Condensate	Brent	53.57 USD/STB
Sub Saharan Africa	LNG	Brent	71.42 USD/STB
Sub Saharan Africa	LNG	JKM netback	7.33 $/MMBTU

1.3 OPERATING COSTS, DEVELOPMENT COSTS AND ABANDONMENT COSTS

Operating costs, Development Costs and Abandonment costs were supplied by Eni and were reviewed by SGS on a high level. Most of the development costs are based on tendering from, and bids already awarded to, qualifying and reputable construction companies. The costs estimates seem to be reasonable and in line with similar developments. The operating cost profiles assume present conditions and were held constant throughout the field's life. Under the production license's terms and conditions Eni is allowed to recover all exploration costs related to this development incurred in the past, which has an impact on the reserves entitlement. The estimated net cost of abandoning the field and facilities was included in the economic evaluation. Some 33% of the total development costs have already been spent by end 2018.

2. STANDARDS OF INDEPENDENCE AND PROFESSIONAL QUALIFICATION

2 SGS CERTIFICATION

Founded in 2001, SGS Horizon B.V. (now merged with SGS Nederland B.V, becoming its Subsurface consultancy division) based in The Netherlands, became part of the SGS Group in April 2008. Based in Switzerland, the SGS Group is the world's leading inspection, verification, testing and certification company. Recognized as the global benchmark for quality and integrity and independency, SGS Group globally employs over 95, 000 people and operate a network of more than 2,400 offices around the world.

As part of SGS' Oil, Gas and Chemicals Services, SGS Nederland B.V. provides integrated solutions throughout the field lifecycle, covering all subsurface, well and engineering aspects from exploration through development and production to abandonment. SGS also performs data room exercises and unitization/redetermination evaluations as well as estimation, auditing, classification and categorization of reserves and resources.

In the subject of reserves assessment, the in-house expertise has been acquired by senior personnel typically having significant pertinent industry experience within SGS or with oil majors, generally in positions of reserves related responsibility.

2.2 INDEPENDENCY

The SGS Group is known for its quality, integrity and independency. These values are also well embedded into the actions, and operations of the staff of the service group related to reserves certifications. The SGS Group nor any of its subsidiaries have any financial interests in Eni or in any of its affiliates. This includes potential shares in Eni. Fees are project-based and are not dependent on the outcome of the evaluation.

2.3 PRIMARY TECHNICAL PERSON UNDERTAKING THE RESERVES AUDIT

The technical, geological, commercial- and economic analyses performed have been carried out by a well experienced team, covering geoscientists, facilities engineers, petroleum engineers and economists from SGS. The qualifications of the technical person primarily responsible for the execution of this audit are provided in Appendix 2.

2.4 TERMS OF USE

This signed copy of this letter has been prepared for public disclosure in its entirety, in conjunction with Eni's annual filings to the SEC.

Very truly yours,

SGS Nederland B.V.
Primary Technical and
Commercial Person

Niek Dousi
Date: March 22nd, 2019

SGS Nederland B.V.

Richard Keen, Operations Manager
Date: March 22nd, 2019

APPENDIX 1

DEFINITIONS OF OIL AND GAS RESERVES

From the U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10 (a)

(a) Definitions

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- Same environment of deposition;
- Similar geological structure; and
- Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

(7) Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in pail as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

(15) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter

(from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities, they become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, arid fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) 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.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

(27) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) 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 paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.

APPENDIX 2

QUALIFICATIONS OF TECHNICAL PERSON PRIMARILY RESPONSIBLE FOR OVERSEEING THIS RESERVES AUDIT:

Niek Dousi, Senior Reservoir Engineer was the project manager and primary technical person primarily responsible for the execution and QA/QC of this audit. Niek Dousi has about 14 years of experience as a reservoir/petroleum engineer and has been involved in many reserves evaluations as technical staff/coordinator and project manager within SGS. In his role, he has been supported by key technical- and commercial specialists, some with over 30 years of professional experience in international oil and gas companies. Mr. Dousi holds an MSc in Petroleum Engineering from Delft University of Technology in The Netherlands. He joined SGS in 2005 and has participated as (lead) reservoir engineer and/or project manager in integrated reservoir studies, Acquisition and Divestment asset valuations and reserves assessments, using SPE-PRMS& SEC regulations. He has worked on assets primarily in the North Sea, Central Europe, North-, West- and East Africa, Oman and Australia. He has participated in numerous studies of oil- and gas assets worldwide, including tight gas, gas condensates, heavy oil, fluvial-, stacked- and fractured carbonate reservoirs. He is a long-standing member of the Society of Petroleum Engineers and has prepared- and presented papers for SPE and EAGE conferences.