ENI SPA
Form 20-F
March 22, 2017
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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, 2016

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)
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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 shares3,634,185,330
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
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, 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 simil 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 engaged 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.

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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	
AEEGSI (Authority for Electricity Gas and Water) formerly AEEG (Authority for Electricity and Gas)	The Regulatory Authority for Electricity Gas and Water 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.
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.

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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.

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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 in use in African, Middle Eastern, Far Eastern and Latin American countries, among others, regulating 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.

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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.
Strategic Storage	According to Legislative Decree No. 164/2000, these are volumes required for covering lack or reduction of supplies from extra-European sources or crises in the natural gas system.
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.

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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	=	barrels
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	= 1 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)

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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, 2012, 2013, 2014, 2015 and 2016. Effective January 1, 2016, management elected to modify the accounting method to recognize exploration expenses and adopted the successful-effort-method (SEM). SEM is largely adopted by oil&gas companies, to which Eni is increasingly comparable given the recent re-focalization of the Group activities on its core upstream business. Under the SEM, geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an unproved tangible asset until the drilling of the well is complete and the results have been evaluated. If commercially viable quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an unproved asset. If it is determined that development will not occur then the costs are recorded as expenses. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons are initially capitalized as an unproved tangible asset. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to proved property.

In accordance to IAS 8 “Accounting policies, Changes in accounting estimates and Errors”, the retrospective application of the SEM has required adjustment of the opening balance of the retained earnings and other comparative balance sheet items as of January 1, 2014. Specifically, the opening balance of the carrying amount of property, plant and equipment was increased by €3,524 million, intangible assets by €860 million and the retained earnings by €3,001 million. Other adjustments related to deferred tax liabilities and other minor line items. Please refer to Note 1 to the Consolidated Financial Statements for further information.

On January 22, 2016, Eni Group divested its Engineering & Construction segment (“E&C”), following the closing of the sale of a 12.503% stake in Saipem SpA to an Italian state-owned agency, CDP Equity SpA, and the concurrent efficacy of a shareholder agreement between Eni and CDP Equity SpA, which established the joint control of the two parties over the target entity. Those transactions triggered the loss of control of Eni over Saipem, which was the parent company of the E&C segment. Therefore, effective January 1, 2016, Saipem revenues and expenses, assets and liabilities have been derecognized. The retained interest of 30.55% in Saipem has been recognized as an investment in an equity-accounted joint venture. The initial carrying amount of the investment was aligned to the share price at the closing date of the transaction (€4.2 per share, equal to €564 million) recognizing a loss through profit of €441 million, as part of the result of the discontinued operations of 2016. Considering the pro-quota share capital increase of Saipem subscribed by Eni for a cash out of €1,069 million, the initial carrying amount of the investment amounted to €1,614 million. At the end of February 2016, Saipem reimbursed intercompany loans owed to Eni (€5,818 million as of December 31, 2015) by using the proceeds from the share capital increase and new credit facilities from third-party financing institutions.

Eni’s Chemical business, managed by the wholly-owned subsidiary Versalis, has been reclassified as continuing operations, with retrospectively effects on the comparative information. In accordance with IFRS 5, Versalis has ceased to be classified as discontinued operations due to termination of the

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negotiations with US-based SK Capital hedge fund, who had shown an interest in acquiring a majority stake in Versalis. In Eni's Annual Report on Form 20-F 2015 this business was reported as discontinued operations. Consequently, Eni's management reinstated the criteria of the continuing use to evaluate Versalis by aligning its book value to the recoverable amount, calculated as the higher of fair value less cost to sell and value-in-use. Conversely, under IFRS 5 Versalis was measured at the lower of its carrying amount and fair value less cost to sell. This change in the accounting of Versalis marginally affected the opening balance of Eni's consolidated net assets (an increase of €294 million) and was neutral on the Group's net financial position. The results of Versalis have been aggregated with those of R&M, in the reportable segment "R&M and Chemicals" because the two segments have similar economic characteristics. This has been retrospectively applied to the selected historical financial data for all comparative periods.

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,				
	2012	2013	2014	2015	2016
	(€ million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	115,419	104,117	98,218	72,286	55,762
Operating profit (loss) by segment from continuing operations					
Exploration & Production	19,190	15,349	10,727	(959)	2,567
Gas & Power	(3,129)	(2,923)	64	(1,258)	(391)
Refining & Marketing and Chemicals	(1,941)	(2,261)	(2,811)	(1,567)	723
Corporate and Other activities	(641)	(736)	(518)	(497)	(681)
Impact of unrealized intragroup profit elimination and other consolidation adjustments (1)	2,094	928	1,503	1,205	(61)
Operating profit (loss) from continuing operations	15,573	10,357	8,965	(3,076)	2,157
Net profit (loss) attributable to Eni from continuing operations	4,870	5,808	1,720	(7,952)	(1,051)
Net profit (loss) attributable to Eni from discontinued operations	3,520	(488)	(417)	(826)	(413)
Net profit (loss) attributable to Eni	8,390	5,320	1,303	(8,778)	(1,464)
Data per ordinary share (euro) (2)					
Operating profit (loss):					
– basic	4.30	2.86	2.48	(0.85)	0.60
– diluted	4.30	2.86	2.48	(0.85)	0.60
Net profit (loss) attributable to Eni basic and diluted from continuing operations	1.34	1.60	0.48	(2.21)	(0.29)
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.97	(0.13)	(0.12)	(0.23)	(0.12)
Net profit (loss) attributable to Eni basic and diluted	2.32	1.47	0.36	(2.44)	(0.41)
Data per ADR ($) (2) (3)					
Operating profit (loss):					

– basic	11.05	7.59	6.59	(1.90)	1.33
– diluted	11.05	7.59	6.59	(1.90)	1.33
Net profit (loss) attributable to Eni basic and diluted from continuing operations	3.45	4.26	1.27	(4.90)	(0.65)
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	2.50	(0.36)	(0.31)	(0.51)	(0.25)
Net profit (loss) attributable to Eni basic and diluted	5.95	3.90	0.96	(5.41)	(0.90)

(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 2016 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on April 13, 2017.

(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/US$ average 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 2012 through 2014 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 2016 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 (euro 0.80 per ADR) at the Noon Buying Rate recorded on the payment date on September 15, 2016, while the balance of euro 0.80 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2016. The balance dividend for 2016 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on April 26, 2017 to holders of Eni shares, being the ex-dividend date April 24, 2017, while ADRs holders will be paid on May 8, 2017.

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	As of December 31,				
	2012	2013	2014	2015	2016
	(€ million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	144,208	142,426	150,366	139,001	124,545
Short-term and long-term debt	24,192	25,560	25,891	27,793	27,239
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Minority interest	3,357	2,842	2,455	1,916	49
Shareholders' equity - Eni share	62,066	61,211	63,186	55,493	53,037
Capital expenditures from continuing operations	12,452	11,221	11,178	10,741	9,180
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,623	3,623	3,610	3,601	3,601
Dividend per share (euro) (1)	1.08	1.10	1.12	0.80	0.80
Dividend per ADR ($) (1) (2)	2.82	2.99	2.65	1.77	1.77

(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 2016 is based on the proposal of Eni's management which is submitted to approval at the Annual General Shareholders' Meeting scheduled on April 13, 2017.

(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 2012 through 2014 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 2016 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 (euro 0,80 per ADR) at the Noon Buying Rate recorded on the payment date on September 15, 2016, while the balance of euro 0.80 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2016. The balance dividend for 2016 once the full-year dividend is approved by the Annual General Shareholders' Meeting is payable on April 26, 2017 to holders of Eni shares, being the ex-dividend date April 24, 2017 while ADRs holders will be paid on May 8, 2017.

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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, 2012, 2013, 2014, 2015 and 2016.

	Year ended December 31,				
	2012	2013	2014	2015	2016
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,084	3,079	3,077	3,372	3,230
of which developed	1,762	1,831	1,847	2,100	2,190
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	266	148	149	187	168
of which developed	44	35	46	48	43
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	14,190	14,442	14,808	14,302	18,462
of which developed	8,965	8,542	8,342	8,899	9,244
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	6,767	3,726	3,737	3,993	3,871
of which developed	424	34	120	1,402	1,905
Proved reserves of hydrocarbons of consolidated subsidiaries in mmBOE at period end	5,667	5,708	5,772	5,975	6,613
of which developed	3,394	3,387	3,366	3,720	3,884
Proved reserves of hydrocarbons of equity-accounted entities in mmBOE at period end	1,499	827	830	915	877
of which developed	122	40	67	303	391
Average daily production of liquids (KBBL/d) (1)	882	833	828	908	878
Average daily production of natural gas available for sale (mmCF/d) (1)	4,118	3,868	3,782	4,284	4,329
Average daily production of hydrocarbons available for sale (KBOE/d) (1)(4)	1,631	1,537	1,517	1,688	1,671
Hydrocarbon production sold (mmBOE)	598.7	555.3	549.5	614.1	608.6
Oil and gas production costs per BOE (2)	10.82	12.19	12.00	9.18	7.79
Profit per barrel of oil equivalent (3)	17.33	16.19	9.86	(3.83)	1.98

(1)
Referred to Eni's subsidiaries and its equity-accounted entities. Natural gas production volumes exclude gas consumed in operations (383, 451, 442, 397 and 478 mmCF/d in 2012, 2013, 2014, 2015 and 2016, respectively).

(2)
Expressed in U.S. dollars. Consists of production costs of consolidated subsidiaries (costs incurred to operate and maintain wells and field equipment including also royalties) 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".

(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.

(4)
From January 1, 2016, as part of a regular reviewing procedure, Eni has updated the conversion rate of gas to 5,458 cubic feet of gas equals 1 barrel of oil (it was 5,492 cubic feet of gas per barrel in previous reporting periods). This update reflected changes in Eni’s gas properties that took place in the last three years and was assessed by collecting data on the heating power of gas in all Eni’s gas fields currently on stream. The effect of this update on production expressed in boe for the full year 2016 was 5 kboe/d. Other per-boe indicators were only marginally affected by the update (e.g. realization prices, costs per boe) and negligible was the impact on depletion charges. Other oil companies may use different conversion rates.

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Selected Operating Information continued

	Year ended December 31,				
	2012	2013	2014	2015	2016
Sales of natural gas to third parties (1)	77.87	77.67	76.11	79.06	77.24
Natural gas consumed by Eni (1)	6.43	5.93	5.62	5.88	6.10
Sales of natural gas of affiliates (Eni's share) (1)	8.29	6.96	4.38	2.78	2.97
Total sales and own consumption of natural gas of the Gas & Power segment (1)	92.59	90.56	86.11	87.72	86.31
E&P natural gas sales in Europe and in the Gulf of Mexico (1)	2.73	2.61	3.06	3.16	2.62
Worldwide natural gas sales (1)	95.32	93.17	89.17	90.88	88.93
Electricity sold (2)	42.58	35.05	33.58	34.88	37.05
Refinery throughputs (3)	30.01	27.38	25.03	26.41	24.52
Balanced capacity of wholly-owned refineries (4)	574	574	404	388	388
Retail sales (in Italy and rest of Europe) (3)	10.87	9.69	9.21	8.89	8.59
Number of service stations at period end (in Italy and rest of Europe)	6,384	6,386	6,220	5,846	5,622
Chemical production (3)	6.09	5.82	5.28	5.70	5.65
Average throughput per service station (in Italy and rest of Europe) (5)	2,064	1,828	1,725	1,754	1,742
Employees at period end (number) (6)	36,018	36,678	34,846	34,196	33,536

(1)
Expressed in BCM.

(2)
Expressed in TWh.

(3)
Expressed in mmtonnes.

(4)
Expressed in KBBL/d.

(5)
Expressed in thousand liters per day.

(6)
Realting to continuing operations for all periods presented.

Exchange Rates

The following tables set forth, for the periods indicated, certain information regarding the Noon Buying Rate in U.S. dollars per euro, rounded to the second decimal (Source: The Federal Reserve Board).

	High	Low	Average (1)	At period

				end
	(U.S. dollars per €)			
Year ended December 31,				
2012	1.35	1.21	1.29	1.32
2013	1.38	1.28	1.33	1.38
2014	1.39	1.21	1.33	1.21
2015	1.20	1.05	1.11	1.09
2016	1.15	1.04	1.10	1.06

(1)
Average of the Noon Buying Rates for the last business day of each month in the period.

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	High	Low	At period end
	(U.S. dollars per euro)		
September 2016	1.13	1.12	1.12
October 2016	1.12	1.09	1.10
November 2016	1.11	1.06	1.06
December 2016	1.08	1.04	1.06
January 2017	1.08	1.04	1.08
February 2017	1.08	1.05	1.06

Fluctuations in the exchange rate between the euro and the dollar affect the dollar equivalent of the euro price of the Shares on the Telematico and the dollar price of the ADRs on the NYSE. Exchange rate fluctuations also affect the dollar amounts received by owners of ADRs upon conversion by the Depository of cash dividends paid in euro on the underlying Shares. The Noon Buying Rate on March 10, 2017 was $1.07 per €1.00.

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 and cash flow and future rate of growth are exposed to the effects of fluctuating 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. From mid-2014, the oil industry has been negatively affected by a sharp price downturn driven by global oversupplies and a slowdown in macroeconomic growth. Over this time span, the price of crude oil has lost approximately 50% of its value. In 2016, after dropping below $30 per barrel ("BBL"), the price of Brent crude has staged a recovery to close at around $50 per barrel at year-end as a result of a less unfavorable supply-demand balance. This was helped by the agreement reached in late 2016 by producing countries belonging to the Organization of the Petroleum Exporting Countries ("OPEC") and other non-member countries to cut the output. For the full year ("FY") 2016, the benchmark Brent price averaged $43.7 per barrel, a reduction of approximately 17% compared to 2015;

- global political developments, including sanctions imposed on certain producing countries and conflict situations;

- global economic and financial market conditions;

- the influence of the OPEC over 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 development and deployment of new technologies for the recovery of crude oil and natural gas reserves and technological advances affecting energy consumption; and

- the effect of worldwide energy conservation and environmental protection efforts intended to reduce greenhouse gas (“GHG”) emissions from human activities.

All these factors can affect the balance between global demand and supply for oil and prices of oil.
Management believes that the oil market will gradually recover in the medium-term. We foresee a better balance between demand and supply driven by the recently agreed OPEC cuts and the cooperation of other countries in curbing production and the effects of the reduced investments made by international oil companies during the downturn, while global oil consumptions are expected to grow at a moderate pace. However, management has also evaluated the continuing risks and uncertainties inherent in such forecasts,

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including actual implementation of the production cuts announced by the OPEC, structural changes that have been affecting oil industry – e.g. the increase in oil supply following the U.S. tight oil revolution – the reduced impact of geopolitical crises and the greater role played by renewable energy sources, as well as risks associated with internationally-agreed measures intended to reduce GHG. Based on this outlook, Eni's management has slightly revised to 70 $/BBL from the previous 65 $/BBL its long-term price assumptions of the Brent crude oil marker utilized in the Group financial projections of the 2017-2020 industrial plan and in evaluating recoverability of the carrying amounts of the Group's oil and gas assets. In the 2015 financial statements the adoption of a long-term oil price of 65 $/BBL led to the recognition of impairment losses of €3.4 billion post-tax at our oil&gas assets. Conversely, the upward revision of the long-term assumptions for Brent crude oil prices led to the reversal of previously recognized impairment losses for €1,005 million (post-tax).

Price fluctuations may have a material effect on the Group's results of operations and cash flow. Lower oil prices from period to period negatively affect the Group's consolidated results of operations and cash flow, because revenues are price sensitive; such current prices are reflected in revenues recognized in the 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. Eni estimates that its consolidated net profit and cash flow vary by approximately €0.2 billion for each one dollar change in the price of the Brent crude oil benchmark with respect to the price scenario assumed in Eni's financial projections for 2017 at 55 $/BBL.

In addition to the adverse effect on revenues, profitability and cash flow, lower oil and gas prices could result in debooking of proved reserves, if they become economically unviable in this type of environment, and asset impairments.

Depending on the significance and speed of a decrease in crude oil prices, Eni may also need to review investment decisions and the viability of development projects. Lower oil and gas prices over prolonged periods may also adversely affect Eni's results of operations and cash flow and hence the funds available to finance expansion projects, further reducing the Company's ability to grow future production and revenues. In addition, they may reduce returns from development projects, either planned or implemented, forcing the Company to reschedule, postpone or cancel development projects. The Group is currently planning a capital budget of approximately €31.6 billion in the next four years, excluding expenditures associated with assets which the Group is planning to divest. This capital budget is significantly lower than the Group's previous financial projections, down by 8% on a constant exchange rate basis, which reflect management's approach to be more selective in its spending decisions in a low oil-price environment. 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 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. At the end of March 2016, both agencies lowered Eni's long-term corporate credit rating (to BBB+ and Baa1, respectively).

Eni estimates that movements in oil prices affect approximately 50% of Eni's current production. The remaining portion of Eni's current production is insulated from crude oil price movements considering that the Company's property portfolio is characterized by a sizeable presence of production sharing contracts, where, due to the cost recovery mechanism, the Company is entitled to a larger number of barrels in case of a decline 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).

Because of the above mentioned risks, an extended continuation of the current commodity price environment, or further declines in commodity prices, will materially and adversely affect the Group's business prospects, financial condition, results of operations, cash flows, liquidity, ability to finance planned capital expenditures and commitments and may impact shareholder returns, including dividends and the share price.

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In gas markets, price volatility reflects the dynamics of demand and supply for natural gas. In recent years, in the face of weak demand dynamics in Europe due to the economic downturn and competition from coal and renewable sources in the production of gas-fired power, gas supplies in Europe have continued to rise. Factors underlying this rise comprise the increased availability of liquefied natural gas ("LNG") on a global scale, which in the future will be fuelled by an expected growth in LNG exports from the U.S. and the Asia-Pacific region, and volumes of contracted supplies of European gas wholesalers under long-term arrangements with take-or-pay clauses. See also the other trends described in the risk factors relating to Eni's Gas & Power business below. The increased liquidity of European hubs has put significant downward pressure on spot prices. Eni expects those trends to continue in the foreseeable future due to a weak outlook for gas demand and continued oversupplies. If Eni fails to renegotiate its long-term gas supply contracts in order to make its gas competitive as market conditions evolve, its profitability and cash flow in the Gas & Power segment would be significantly further affected by current downward trends in gas prices.

The Group's results from its Refining & Marketing and Chemicals businesses are primarily dependent upon the supply and demand for refined and chemicals products and the associated margins on refined product 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.

Competition

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

Eni faces strong competition in each of its business segments.

In the current uncertain financial and economic environment, Eni expects that prices of energy commodities, in particular oil and gas, will be very volatile, with average prices and margins influenced by changes in the global supply and demand for energy, as well as in the market dynamics. This is likely to increase competition in all of Eni's businesses, which may impact costs and margins. Competition affects licence costs and product prices, with a consequent effect on Eni's margins and its market shares. Eni's ability to remain competitive requires continuous focus on technological innovation, reducing unit costs and improving efficiency. It also depends on Eni's ability to get 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 relatively smaller size compared to other international oil companies, particularly when bidding for large scale or capital intensive projects, and may be exposed to 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 may be adversely affected.

- In the Gas & Power segment, Eni faces strong competition from gas and energy players to sell gas to the industrial segment, the thermoelectric sector and the retail customers both in the Italian market and in markets across Europe. Competition has been fuelled by ongoing weak trends in demand due to the downturn and macroeconomic uncertainties and continued oversupplies in the marketplace. These have been driven by rising production of LNG on global scale and inter-fuel competition. In the latest years the use of gas in gas-fired power plants has been negatively affected by an increase use of coal in firing power plants due to cost advantages and a dramatic growth in the adoption of renewable sources of energy (photovoltaic and solar). The large-scale development of shale gas in the United States was another fundamental trend that aggravated the oversupply situation in Europe because many LNG projects that originally targeted the U.S. market instead provided extra supply to the already saturated European sector. The continuing growth in the production of shale gas in the United States has increased global gas supplies. These market imbalances in Europe were exacerbated by the fact that throughout the last decade and up to a few years ago the market consensus projected that gas demand in the continent would grow steadily until 2020 and beyond, driven by economic growth and the increased adoption of gas in firing power production. European gas wholesalers including Eni committed to purchasing large amounts of gas under long-term supply contracts with so-called “take-or-pay” clauses from the

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main producing countries bordering Europe (namely Russia, the Netherlands, Norway and Algeria). They also made significant capital expenditures to upgrade existing pipelines and to build new infrastructures in order to expand gas import capacity to continental markets. Long-term gas supply contracts with take-or-pay clauses expose gas wholesalers to a volume risk, as they are contractually required to purchase minimum annual amounts of gas or, in case of failure, to pay the underlying price. Due to the trends described above of the prolonged economic downturn and inter-fuel competition, the projected increases in gas demand failed to materialize, resulting in a situation of oversupply and pricing pressure. As demand contracted across Europe, gas supplies increased, thus driving the development of very liquid continental hubs to trade spot gas. Spot prices at continental hubs have become the main benchmarks to which selling prices are indexed across all end-markets, including large industrial customers, thermoelectric utilities and the retail segment. The profitability of gas operators was negatively impacted by falling sales prices at those hubs, where prices have been pressured by intense competition among gas operators in the face of weak demand, oversupplies and the constraint to dispose of minimum annual volumes of gas to be purchased under long-term supply contracts. Eni does not expect any significant improvement in the European gas sector in the near future. We are currently projecting weak gas demand trends due to macroeconomic uncertainties and unclear EU policies regarding how to satisfy energy demand in Europe and the energy mix. Additionally, supplies at continental hubs will continue to build given the expected ramp-up of LNG exports from the United States due to steady growth in gas production and ongoing projects to reconvert LNG regasification facilities into liquefaction export units and the start of several LNG projects in the Pacific region and elsewhere. Eni believes that these ongoing negative trends may adversely affect the Company’s future results of operations and cash flows, also taking into account the Company’s contractual obligations to off-take minimum annual volumes of gas in accordance with its long-term gas supply contracts with take-or-pay clauses.

- In its Gas & Power segment, Eni is vertically integrated in the production of electricity via its gas-fired power plants, which currently use the combined-cycle technology. In the electricity business, Eni competes with other producers and traders from Italy or outside Italy who sell electricity in the Italian market. Going forward, the Company expects continuing competition due to the projections of moderate economic growth in Italy and Europe over the foreseeable future, also causing outside players to place excess production on the Italian market. The economics of the gas-fired electricity business have dramatically changed over the latest few years due to ongoing competitive trends. Spot prices of electricity in the wholesale market across Europe decreased due to excess supplies driven by the growing production of electricity from renewable sources, which also benefit from governmental subsidies, and a recovery in the production of coal-fired electricity which was helped by a substantial reduction in the price of this fuel on the back of a massive oversupply of coal which occurred on a global scale. As a result of falling electricity prices, margins on the production of gas-fired electricity went into negative territory. Eni believes that the profitability outlook in this business will remain weak in the foreseeable future.

- In the Refining & Marketing segment, Eni faces strong competition both in industrial and in commercial activities. In 2016 refining margins decreased by approximately 50% y-o-y due to overcapacity in Europe, global oversupplies and strong competition from cheaper products stream coming from more efficient refiners in the Middle East, in Asia and elsewhere. Looking forward, management believes that refining margins will remain under pressure in the foreseeable future and will hover around $4 per barrel in the next couple of years, level at which our refining business is currently barely profitable. In marketing, Eni faces the challenges of growing competition from operators without brands and large retailers, which leverage on the price awareness of final consumers to increase their market share.

- In the Chemical business, Eni faces strong competition from well-established international players and state-owned petrochemical companies, particularly in the most commoditized segments such as the production of basic petrochemical products and plastics. Many of those competitors based in the Far East and the Middle East are able to benefit from cost advantages due to scale, favorable environmental regulations, availability of cheap feedstock and proximity to end-markets. Excess capacity and sluggish economic growth in Europe have exacerbated competitive pressures with negative impacts on profitability. Furthermore, petrochemical producers based in the United

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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. The Company expects continuing margin pressures in its petrochemical segment in the foreseeable future as a result of those trends.

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. 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 business entail health, safety and environmental risks related to the handling, transformation and distribution of oil and oil products. These risks arise from the inherent characteristics of hydrocarbons, in particular flammability and toxicity. Also environmental risks are involved in the use of oil products, such as GHG emissions, soil and groundwater contamination.

Eni's activities in the Refining & Marketing and Chemicals segment also entail health, safety and environmental risks related to the overall life cycle of the products manufactured, and to raw materials used in the manufacturing process, such as oil-based feedstock, catalysts, additives and monomer feedstock. These risks can arise from the intrinsic characteristics of the products involved (flammability, toxicity, or long-term environmental impact such as greenhouse gas emissions and risks of various forms of pollution and contamination of the soil and the groundwater), their use, emissions and discharges resulting from their manufacturing process, 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 invests significant resources in order to upgrade the methods and systems for safeguarding the 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 unexpected 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 distribution networks, and managing its operations in a safe, compliant and reliable manner. Failure to manage these risks could effectively result in unexpected 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.

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In December 2016, an incident occurred at our Eni Slurry Technology unit located in the refinery of Sannazzaro where a fire due to a mechanical fault partially damaged the plant. We recorded a plant write-off of €193 million and a provision for site dismantling and cleanup of €24 million. We did not identify any environmental provision as of the date of this Annual Report. Considering that the value of the plant was partially insured with third parties, the Group loss related to the accident amounted to €95 million.

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 decommissioning of productive infrastructure and environmental site remediation. 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 for all of its subsidiaries, which is designated 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 cleanup and remediation. Particularly, Eni's entities are insured against liabilities for damage to third parties and environmental claims up to $1.2 billion in case of offshore incident and $1.4 billion in case of incident at onshore facilities (refineries). In addition, 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 few 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 occurrence of the events mentioned above 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.

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 loss would not have a material adverse effect on the Company.

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 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&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 2016, approximately 53% of Eni's total oil and gas production for the year derived from offshore fields, mainly in Egypt, Libya, Norway, Italy, Angola, the Gulf of Mexico, Congo, United Kingdom and Nigeria. Offshore operations in the oil and gas industry are inherently riskier than onshore activities. Offshore

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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. Further, 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 operations, results, liquidity, reputation, business prospects and the share price.

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, completing and operating 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, and shortages or delays in the delivery of equipment. The Company also engages in exploration drilling activities offshore, including in deep and ultra-deep waters, in remote areas and in environmentally sensitive locations (such as the Barents Sea). In these locations, the Company generally experiences more challenging conditions and incurs higher exploration costs than onshore or in shallow waters. Failure to discover commercial quantities of oil and natural gas could have an adverse impact on Eni’s future growth prospects, results of operations and liquidity. Because Eni plans to make investments in executing exploration projects, it is likely that the Company will incur significant amounts of dry hole expenses in future years. Some of these activities are high-risk projects that generally involve sizeable plays located in deep and ultra-deep waters or at higher depths where operations are more challenging and costly than in other areas. Furthermore, deep and ultra-deep water operations will require significant time before commercial production of discovered reserves can commence, increasing both the operational and financial risks associated with these activities. In 2016 Eni invested approximately €0.42 billion in exploration projects. The Company plans to invest €2.1 billion in the four-year plan 2017-2020 and to execute exploration projects in the Norwegian Barents Sea, North and West Africa (Nigeria, Egypt, Libya, Congo, Gabon, Angola and Morocco), East Africa (Mozambique, Kenya) and South-East Asia (Indonesia, Vietnam, Myanmar and other locations), the United Kingdom, offshore Gulf of Mexico and offshore Cyprus.

Planned projects will be equally split between low-risk initiatives, involving proven areas and the appraisal of recent discoveries, as well as high-risk plays targeting conventional hydrocarbons. 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.

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 environmentally-sensitive locations. Eni’s future results of operations and liquidity 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, including, for example, Eni’s ability to negotiate favourable long-term contracts to market gas reserves;
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;
- timely issuance of permits and licences by government agencies;
-

the Company's relative size compared to its main competitors which may prevent it from participating in large-scale projects or affect its ability to reap benefits associated with economies of scale;

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the ability to carefully carry out front-end engineering design so as to prevent the occurrence of technical inconvenience during the execution phase;

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- 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;

- poor performance in project execution on the part of contractors who are awarded project construction activities generally based on the EPC (Engineering, Procurement and Construction) – turn key contractual scheme. Eni believes this kind of risk may be due to lack of contractual flexibility, poor quality of front-end engineering design and commissioning delays;

- changes in operating conditions and cost overruns. In recent years, the industry has been adversely impacted by the growing complexity and scale of projects which drove cost increases and delays, including higher environmental and safety costs;

- 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 end markets.

Events such as the ones described above of poor project execution, inadequate front-end engineering design, delays in the achievement of critical events 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. Finally, development and marketing of hydrocarbons 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 its commercial potential, sanctioning a development project and building and commissioning related facilities. As a consequence, rates of return for such long leadtime projects are exposed to the volatility of oil and gas prices and costs which may be substantially different from the prices and costs assumed when the investment decision was actually made, leading to lower rates of return. In addition, 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 capitalized 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

Eni's results of operations and financial condition are substantially dependent on its ability to develop and sell oil and natural gas. 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") and similar contractual schemes. 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 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. The opposite occurs in case of lower oil prices. 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, negotiation with national oil companies and other entities owners of known reserves and acquisitions. In a number of reserve-rich countries, national oil companies decide to develop portions of oil and gas reserves that remain to be developed. To the extent that national oil companies decide to develop those reserves without the participation of international oil companies or if the Company fails to establish partnership with national oil companies, Eni's ability to access or develop additional reserves will be limited.

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An inability to replace produced reserves by finding, 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

Several uncertainties are inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. The accuracy of proved reserve estimates depend on a number of factors, assumptions and variables, among which the most important are the following:

- the quality of available geological, technical and economic data and their interpretation and judgment;
- 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 PSAs and similar contractual schemes.

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 12 month period ending December 31, 2016. For the 12 month period ending December 31, 2016, the average price was 42.8 $/BBL for the Brent crude oil in comparison to a price reference of 54 $/BBL in 2015. This decline in the price of crude oil triggered the downward revision of those reserves that have become uneconomic in this type of environment, amounting to approximately 76 mmBOE, net of higher reserve entitlement in certain PSA contracts due to the cost recovery mechanism: i.e. because of lower oil and gas prices, the reimbursement of expenditures incurred by the Company requires additional volumes of reserves.

Many of these 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.

Accordingly, the estimated reserves reported as of the end of 2016 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 results of operations and financial condition.

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

At December 31, 2016, approximately 43% 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, 2016 includes estimates of total future development costs associated with the Group's proved undeveloped reserves of approximately €39.4 billion (undiscounted). It cannot be certain the estimated costs of the development of these reserves are accurate, development will occur as scheduled, or the results of such development will be

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as estimated. In case of change in the Company's development plans to develop of 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.

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 and, in particular, may be reduced due to the recent significant decline in commodity prices

Investors should not assume the present value of future net revenues from Eni's proved reserves is 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 unweighted 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. In addition, 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, 2016, the net present value of Eni's proved reserves totaled approximately €29.8 billion, calculated in accordance with the requirements of FASB Extractive Activities – Oil & Gas (Topic 932). This value was significantly lower than in 2015 due to reduced commodity prices. The average price used to estimate Eni's proved reserves and the net present value at December 31, 2016, as calculated in accordance with U.S. SEC rules, was 42.8 $/BBL for the Brent crude oil in comparison to 54 $/BBL in 2015. Future prices may materially differ from those used in the Group's year-end estimates.

Political considerations

A substantial portion of Eni's oil and gas reserves and gas supplies are located in countries outside the EU and North America, mainly in Africa, Central Asia and Central-Southern America, where the socio-political framework and macroeconomic outlook is less stable than in the OECD countries. In those less stable countries, Eni is exposed to a wide range of risks and uncertainties, which could materially impact the ability of the Company to conduct its operations in a safe, reliable and profitable manner.

As of December 31, 2016, approximately 85% of Eni's proved hydrocarbon reserves were located in such countries and 60% of Eni's supplies of natural gas came from outside OECD 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 negatively impair Eni's ability to continue operating in an economic 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 enforcement of contractual rights;

- unfavourable enforcement of laws, regulations and contractual arrangements leading, for example, to expropriations, nationalizations or forced divestitures of assets and unilateral cancellation or modification of contractual terms. Eni is facing increasing competition from State-owned oil companies who 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 change contractual terms and other conditions of oil and gas projects in order

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to obtain a larger share of profit from a given project, thereby reducing Eni's profit share. They can also render different interpretations of contractual clauses relating to the recovery of certain expenses incurred by the Company to produce hydrocarbons reserves in any given projects;

- 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 incidents. These risks could result in disruptions to economic activity, loss of output, plant closures and shutdowns, project delays, the loss of personnel or assets. They may force Eni to evacuate personnel for security reasons and to increase spending on security. 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 geographic areas in which Eni operates;

- difficulties in finding qualified suppliers in critical operating environments; and

- complex processes of granting authorisations 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, Iraq and Russia. In addition, any possible reprisals because of military or other action, such as acts of terrorism in the United States or elsewhere, could have a material adverse effect on Eni's business, results of operations and financial condition.

In 2011, Eni's operations in Libya were materially affected by an internal revolution and a change of regime, which has led to a prolonged period of political and social instability characterized by acts of local conflict, social unrest, protests, strikes and other similar events. Those political developments forced Eni to temporarily interrupt or reduce its producing activities, negatively affecting Eni's results of operations and cash flow until the situation began to stabilize. Although the Group's production levels in Libya have returned to levels prior to the outbreak of the civil war, the geopolitical situation remains unstable and unpredictable. In 2016, Eni's production in Libya was 346 kboe/day, the highest level since the outbreak of the civil war, which represented approximately 20% of the Group's total production for the year.

Furthermore, Eni's activities in Nigeria have been impacted in recent years by continuing episodes 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 those countries.

We have factored into our future production levels possible risks of unfavorable geopolitical developments in our main countries of extractive operations. Those risks include temporary production losses and disruptions in the Group's operations in connection with, among other things, acts of war, sabotage, social unrest, clashes and other form of civil disorder. The contingency has been calculated as a haircut to the Group's future production levels based on management's appreciation of those risks, past experience and other considerations. However, this contingency does not cover worst-case developments and worst case events, which could determine a prolonged production shutdown.

Eni closely monitors political, social and economic risks of approximately 70 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.

In the current depressed environment for crude oil prices, the financial outlook of certain countries where Eni's hydrocarbons reserves are located has significantly deteriorated due to lower proceeds from the exploitation of hydrocarbons resources. This trend has increased the risk of sovereign default, which may cause political and macroeconomic instability and trigger one or more of the above mentioned risks. In addition, state-owned petroleum companies of those countries are exposed to liquidity risk. Eni is partnering with those national oil companies in executing certain oil and gas development projects or is currently selling its equity production to national oil companies. Financial difficulties of those national oil companies might jeopardize the financial feasibility of ongoing projects or increase the financial exposure of Eni, which is contractually obliged to finance the share of development expenditures of the partner company in case of a financial shortfall of the latter. This risk is mitigated by the default clause customary in such contracts, pursuant to which which states that in case of a default, the non-defaulting party is entitled to compensate its claims with the share of production of the defaulting party. National oil companies may also delay the repayment of trade receivable due to Eni for the supply of equity hydrocarbons. In view of certain long-overdue exposures related to the supply of equity hydrocarbons, cost recovery and cash call to execute investments, certain of which were also disputed by our counterparties, the Group has entered into arrangements with a number of National Oil Companies. Those arrangements provide for the securitization of amounts due to Eni or repayment plans whereby Eni receivables are reimbursed in instalments with the proceeds of the sale of hydrocarbons produced in mineral initiatives operated by Eni or from elsewhere. Based on ongoing arrangements under discussion to recover part of the overdue amounts, the Group recognized a valuation allowance of approximately €0.41 billion. Furthermore, because the proceeds to reimburse Eni's receivable will derive from the sale of hydrocarbons reserves yet to be developed, those future proceeds are subject to the mineral risk. In these circumstances, the Group recognized through profit the discount effect of those reimbursement plan utilizing a discount factor that factored in the mineral risk of underlying the reimbursement plan. In 2016, we incurred discount expense of approximately €0.13 billion. Furthermore, in 2016 we incurred losses on trade receivables and equity-accounted entities driven by the devaluation of local currencies for approximately €0.28 billion. It is possible that the Group may incur further losses in connection with its commercial and financial exposure towards certain NOCs of countries which are running wide current account deficits in case of an escalation of local financial crises. For a full description of our overdue trade and other receivables outstanding at year-end, see Note 11 to the Consolidated Financial Statements.

An escalation of the political crisis in Russia and Ukraine could affect Eni's business in particular and the global energy supply generally

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.

Approximately 30% of Eni's natural gas is supplied by Russia. These supplies are out of the reach of current sanctions. Furthermore, Eni is currently partnering the Russian company Rosneft in executing two exploration projects in the Russian sections of the Barents Sea and one in the Black Sea. The contracts pertaining to the above-mentioned exploration licenses were entered into before the enactment of the restrictive measures and the competent authorities of the relevant EU Member States waived contracts under execution when the sanctions were firstly enacted. The EU sanction regime has been extend until July 2017; however it is possible that it could change in relation to the evolution of the political situation in Ukraine.

It is possible that wider sanctions targeting the Russian energy, banking and/or finance industries may be implemented. Further sanctions imposed on Russia, Russian individuals 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 future prospects.

Risks in the Company Gas & Power business

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

The outlook of the European gas market remains unfavorable due to oversupply, exacerbated by increased availability of liquefied natural gas ("LNG") globally, and weak demand dynamics. Growth in gas demand has been dampened by sluggish macroeconomic activity in the Eurozone, the increasing use of renewable sources in the production of electricity and the competition from cheaper fossil fuels (like coal) in firing thermoelectric production. Looking forward, management does not expect any meaningful acceleration in gas demand growth in Italy and in Europe and is forecasting an average growth rate lower than 1% in Europe and Italy until 2020.

Against the backdrop of a deteriorating competitive environment, management has periodically renegotiated the Company's long-term supply contracts with take-or-pay clauses, where the Company is

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obliged to offtake a contractually set minimum volume of gas supplies or, in case of failure, to pay the contractual price (see below). The renegotiation has allowed the Company to adjust the original oil-linked indexation mechanism of the purchase costs to market benchmarks at approximately 70% of the Company’s supply portfolio, ensuring better competitiveness for the Group’s gas. However, in spite of those measures, continuing cost efficiencies and other actions intended to boost margins, the Gas & Power business reported an operating loss of €391 million for the FY 2016.

Eni anticipates a number of risk factors to the profitability outlook of the Company’s gas marketing business over the four-year planning period. Those include continuing oversupplies, strong competition and the risk of deterioration in the spread of Italian spot prices versus continental benchmarks. Eni believes that those trends will negatively affect the gas marketing business future results of operations and cash flows by reducing gas selling prices and margins. Eni’s financial outlook has factored in the rigidities of the Company’s long-term supply contracts with take-or-pay clauses. The main source of risk concerns Eni’s wholesale business, the results of which are 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 indexed to spot prices at European hubs, whereas a large part of the Group’s selling volumes are indexed to Italian spot prices.

Against this backdrop, Eni’s management will continue to execute its strategy of renegotiating the Company’s long-term gas supply contracts in order to align pricing and volume terms to current market conditions as they evolve. 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. In particular, management is planning to renegotiate its main long-term supply contracts over the plan period targeting to align supply costs to the expected dynamics in the outlet markets, which will allow the Company to recover logistics costs and G&A costs, targeting to achieve structural breakeven.

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, also the suppliers might file counterclaim with the arbitration panel seeking to dismiss Eni’s request for a price review. All these possible developments within renegotiation processes could possibly 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 fulfill its minimum off-take obligations in connection with its take-or-pay, long-term gas supply contracts

In order to secure long-term access to gas availability, particularly with a view to supplying the Italian gas market and anticipating certain trends in gas demand, which thus far have failed to materialize, Eni has signed a number of long-term gas supply contracts with national operators of certain key producing countries. Most of European gas supplies are sourced from those countries (Russia, Algeria, Libya, the Netherlands and Norway).

These contracts include take-or-pay clauses whereby the Company is required to off-take 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 contractually required to purchase minimum annual amounts of gas or, in case of failure, to pay the underlying price.

Looking forward, management believes that the current market outlook which will be negatively affected by continued oversupplies, weak demand growth, strong competitive pressures as well as any possible change in sector-specific regulation represents a risk to the Company’s ability to fulfill its minimum take obligations associated with its long-term supply contracts. In the medium term, this risk will be mitigated by the expected reduction of the contractual minimum take, due to expiration of some contracts. In this scenario, management is committed to the renegotiation of long-term gas supply contract and to portfolio optimization, in order to reduce the exposure to take-or-pay contracts and to the related financial risk.

Thanks to contract renegotiations and effective selling activities, the Company lifted part of the underlying volumes, the purchase cost of which the Company advanced to its gas supplies in previous years due to the incurrence of the take-or-pay clause. By these means, the Company has achieved over the latest

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years a reduction in its deferred costs recorded in the balance sheet from €2.4 billion at the end of 2012, which was the bottom of the gas downturn, to approximately €0.3 billion as of 2016 year-end. Management plans to substantially finalize the recovery of the residual amounts of gas paid in advance in the next few years, fulfilling contractual clauses and recovering the prepaid amounts.

Environmental, health and safety regulations

Eni has incurred in the past, 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 also regulate emissions of substances and pollutants, handling of hazardous materials and discharges to surface and subsurface of water 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 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 materials.

Breaches of environmental, health and safety laws expose the Company’s employees to criminal and civil liability and the Company to the incurrence of liabilities associated with compensation for environmental, health or safety damage, as well as damage to its reputation. Additionally, in the case of violation of certain rules regarding the safeguard of the environment and safety in the workplace, the Company can be liable for negligent or willful conduct on part of its employees as per Italian Law Decree No. 231/2001.

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 governmental action to address climate change;
- remedial and cleanup 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, in case Eni causes any kind of accident, oil spill, well blowouts, pollution, contamination, emission of GHG above permitted levels or of other hazardous gases or other environmental liability as a result of its operations or 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.

Furthermore, in the countries where Eni operates or expects to operate in the near future, new laws and regulations, the imposition of tougher licence requirements, increasingly strict enforcement or new interpretations of existing laws and regulations or the discovery of previously unknown contamination may also cause Eni to incur material costs resulting from actions taken to comply with such laws and regulations, including:

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- modifying operations;
- installing pollution control equipment;
- implementing additional safety measures; and
- performing site cleanups.

As a further result of any new laws and regulations or other factors, Eni may also have 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, including profits and cash flow. Security threats require continuous assessment and response measures. Acts of terrorism against Eni's plants, installations, platforms and offices, pipelines, transportation or computer systems could severely disrupt businesses and operations and could cause harm to people and the environment.

Risks of environmental, health and safety incidents and liabilities are inherent in many of Eni's operations and products. Although 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. 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 business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders' return and damage to the Group 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 regulations and, from time to time, such claims have been made against us. In Italy, environmental requirements and regulations typically impose strict liability. Strict liability means that in some situations Eni could be exposed to liability for clean-up and remediation costs, natural resource damage, and other damage as a result of Eni's conduct of operations that was lawful at the time it occurred or 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.

Eni has been sued from time to time for alleged environmental crimes and liabilities in relation to the majority of its proprietary areas in Italy where the Company has conducted industrial operations over the years. Many of these proceedings are currently underway. The majority of those potential liabilities relate to certain industrial activities that the Company disposed of, liquidated, closed or shut down in prior years where Group products were produced, processed, stored, distributed or sold, such as chemical plants, mineral-metallurgic plants, refineries and other facilities. At those industrial hubs, Eni has undertaken a number of initiatives to restore and clean-up proprietary or concession areas that were allegedly contaminated and polluted by the Group's industrial activities. The Group believes that it cannot be held liable for contaminations which occurred in past years (as permitted by applicable regulations in case of declaration rendered by a guiltless owner i.e. as a result of Eni's conduct that was lawful at the time it occurred) or because Eni took over operations from third parties. However, 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.

Eni expects remedial and clean-up activities at Eni's dismantled sites to continue in the foreseeable future impacting Eni's liquidity. The Group has accrued risk provisions to cope with all existing environmental liabilities whereby both a legal or constructive obligation to perform a clean-up or other remedial actions is in place and the associated costs can be reasonably estimated. The accrued amounts represent the management's best estimates of the Company's existing liabilities for environmental and associated matters.

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 of Eni’s industrial sites as required by the applicable regulations on contaminated sites; (iii) unfavorable 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

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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 liquidity, results of operations, consolidated financial condition, business prospects, reputation and shareholders' value, including dividends and the share price.

Laws and regulations related to climate change may adversely affect the Group's businesses

Growing public concern in a number of countries over GHG emissions and climate change, as well as a multiplication of stricter regulations in this area, could adversely affect the Group's businesses, increase its operating costs and reduce its profitability.

The scientific community has established a link between climate change and increasing GHG emissions. The worldwide goal to limit global warming has led to the need to gradually reduce fossil fuel use notably through the diversification of the energy mix. The share of natural gas, the least GHG-emitting fossil energy source, represented 48% of Eni's production in 2016 on available-for-sale basis; as of December 31, 2016, gas reserves represented approximately 51% of our total proved reserves of our subsidiary undertakings.

In December 2015, a global climate agreement involving 195 countries was reached in Paris at the 21st Conference of Parties organized by the United Nations under the Framework Convention on Climate Change. The Agreement has set the goal to limit well below the 2° C the increase in global temperature compared to pre-industrial parameters. On November 4, 2016, the Paris Agreement was ratified. However, the voluntary commitments taken by the ratifying countries are insufficient to reach the 2°C goal. Nonetheless, the agreement may result in increased political pressure worldwide to adopt measures intended to reduce and monitor GHG emissions and may spur further initiatives aimed at reducing GHG emissions in the future.

Changes in environmental requirements related to GHG and climate change may negatively impact demand for oil and natural gas and production may decline as a result of environmental requirements targeting the reduction of GHG emissions (including land use policies responsive to environmental concerns). State, national, and international governments and agencies have been evaluating climate-related legislation and other regulatory initiatives that would restrict emissions of GHG in areas in which Eni conducts business. Because Eni's business depends on the global demand for oil and natural gas, 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, could have a negative impact on Eni's business if such laws, regulations, treaties, or international agreements reduce the worldwide demand for oil and natural gas. Some governments have introduced carbon pricing mechanisms, which can be an effective measure to reduce GHG emissions across the economy at lowest overall cost to society. We expect more governments to follow and governments may also require companies to apply technical measures to reduce their GHG emissions. These latter may result in additional compliance obligations with respect to the release, capture, sequestration, and use of carbon dioxide that could result in increased investments and higher project costs for us and could have a material adverse effect on Eni's liquidity, consolidated results of operations, and consolidated financial condition.

The adoption and implementation of regulations that require reporting of GHG or otherwise limit emissions of GHG from the Group's equipment and operations could require us to incur costs to monitor and report on GHG emissions or install new equipments, to reduce emissions of GHG associated with the Group's operations.

Our portfolio exposure is reviewed annually against changing GHG regulatory regimes and physical conditions to identify emerging risks. To test the resilience of new projects, we assess potential costs associated with GHG emissions when evaluating all new capital projects. Our approach applies a uniform cost of €40 (real terms) per tonne of carbon dioxide (CO2) equivalent to the total GHG emissions of each investment. This review has concluded that the internal rates of return of our ongoing projects will be only marginally affected by a carbon pricing mechanism. The project development process features a number of checks that may require development of detailed GHG and energy management plans. High-emitting projects undergo additional sensitivity testing, including the potential for future CCS (Carbon Capture and Storage) projects. Projects in the most GHG-exposed asset classes have GHG intensity targets that reflect

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standards sufficient to allow them to compete and prosper in a more CO2 regulated future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when 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 of the International Energy Agency (IEA) 450 Scenario as updated in November 2016 (450s WEO 2016). This review has covered a panel of oil&gas CGUs, which were selected based on certain parameters, including amount of the capital employed, emission intensity, reserve life and other risk factors. Those CGUs represented approximately 30% of the Group capital employed in the E&P segment. The IEA 450 Scenario sets out an energy pathway consistent with the goal of limiting the average global temperature increase to 2°C. This is accomplished by seeking to limit the concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO2 equivalent. By the year 2030, the IEA's 450 Scenario describes an energy sector with significant renewables penetration, marked improvement in vehicle as well as process efficiency, and widespread replacement of coal by natural gas in power generation. The IEA has assumed oil and gas prices in 2030 of around \$113 per barrel and \$12.5 per MMbtu respectively, and global CO2 equivalent costs of \$133 per tonne (all in nominal terms). The related impact on expected production is that global demand for oil would fall by 17% between 2015 and 2030, while demand for natural gas would grow by 8% during that period. The IEA's projected GHG regulation and demand scenario are expected to result in lower demand for some of our products and potential albeit immaterial impairments to some of our less energy efficient assets. However, we could also see certain benefits as a robust global CO2 price would make some forms of energy, such as natural gas and renewables, more competitive compared with coal. Our preliminary view, looking at 2030, is that the aggregate impact under the IEA's 450 Scenario would be positive overall for us compared with our own outlook. This is primarily due to the higher oil and gas prices assumed by the IEA. While the IEA assumes significant global CO2 costs of \$133/tonne (in nominal terms) in 2030, our portfolio sensitivity to oil and gas prices exceeds our sensitivity to CO2 costs associated with our GHG emissions.

Finally, it should be noted some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods or other climatic events. If any such effects were to occur because of climate change or otherwise, they could have an adverse effect on the Group's assets and operations.

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

Eni is the defendant in a number of civil actions and administrative proceedings arising in the ordinary course of business. In addition to existing provisions accrued as of the latest balance sheet date to account for ongoing proceedings, it is possible that in future years Eni may incur significant losses in addition to the amounts already accrued in connection with pending 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 where Eni or its subsidiaries or its officers are parties involve the alleged breach of anti-corruption laws and regulations and ethical misconduct. Ethical misconduct and noncompliance with applicable laws and regulations, including noncompliance with anti-bribery and anti-corruption laws, by Eni, 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. See "Note 38 – Guarantees, commitments and risks – Legal proceedings, in the Consolidated Financial Statements".

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

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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 connected to acquisitions materialize, 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. In general, the effects of climate change could result in less stable weather patterns, resulting in more severe storms and other weather conditions that could interfere with Eni's operations and damage Eni's facilities. Furthermore, Eni's operations, particularly offshore production of oil and natural gas, are exposed to extreme weather phenomena that can result in material disruption to Eni's operations and consequent loss or damage of properties and facilities, as well as a loss of output, revenues, maintenance and repair expenses and cash flow shortfall.

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 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 inherently exposed to financial risk. This 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 optimise 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 (OTC) 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

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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.

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 Notes or other 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. European and global financial markets are currently subject to volatility amid uncertainties relating to a weak macroeconomic outlook, particularly in the Euro-zone, and the financial stress of certain emerging economies or countries whose financial conditions depends upon the proceeds of the sale of hydrocarbon resources following a prolonged slump in commodity 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 growth rate, 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, exploitation and production of oil and natural gas reserves. The Company’s capital budget for the four-year plan 2017-2020 amounts to €31,6 billion, net of capex associated with the planned asset disposals, and is significantly lower than the Group’s previous industrial plan (down by an estimated 8% at constant exchange rates) as a result of a planned reduction in spending prompted by weak commodity prices and a more selective approach to spending compared to the past. The Company has budgeted approximately €7.8 billion for capital expenditure in 2017, which is 18% lower than in 2016 at constant exchange rates. Management may find that additional reductions in Eni’s capital budget become necessary depending on market conditions.

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 equipments, 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.
With respect to the 2017-2020 business plan in particular, management expects to deliver approximately €5-7 billion of additional cash flows from asset disposals, the main part of which will comprise the divestment of stakes in the Group's exploration assets thereby in essence monetizing some of the Group's recent exploration successes and reserves. These additional cash flows are intended to provide the Group with further financial flexibility in view of funding organic growth and the Group's planned shareholder distributions in a manner consistent with the Group's target capital structure. The Company is seeking to complete such disposals in large part within 2017. However, asset disposals are subject to execution risk and may fail to be completed, and the proceeds received from such disposals may not reflect valuations that management currently believes are achievable, particularly if the disposals are carried out in difficult market conditions. The failure to achieve the planned disposal program could negatively affect the achievement of the Group's financial targets forcing us to either curtail capital expenditure thus hampering growth or take on more finance debt.
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 latest 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

and the amount of trade receivables overdue at the balance sheet date has increased significantly. Furthermore, a collapse in oil prices has stressed the financial condition of many State-owned entities, which are party to the Group's upstream projects for exploring and developing hydrocarbons or are buyers of Eni's equity production. In the 2016 Consolidated Financial Statements, we accrued an allowance against doubtful trade accounts amounting to €503 million, mainly relating to the Gas & Power business segment in relation to Italian retail customers who were experiencing financial difficulties. Management believes that this business 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 impacted by the financial and economic downturn. Eni believes that

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the management of doubtful accounts represents an issue to the Company, which will require management focus and commitment going forward. In the future Eni cannot exclude the recognition of significant provisions for doubtful accounts. Considering the deteriorated financial outlook of many oil-producing countries where Eni is conducting its upstream operations due to a prolonged decline in commodity prices, management is strictly monitoring exposure to the counterpart risk in its Exploration & Production ("E&P") segment. The financial difficulties of certain countries also involve state-owned oil companies who are partnering Eni in the execution of development projects of hydrocarbons reserves or who are buying Eni's share of production in joint projects. In 2016, we incurred approximately €0.4 billion of losses related to the expected outcome of certain renegotiations to settle disputed amounts or to establish repayment plans of certain overdue receivables owed by few National Oil Companies. Due to the prolonged financial downturn of certain countries hit by a fall in petroleum revenues, it is possible that the Group may incur further counterparty losses in the future. For further information see the paragraph "Political Considerations" above.

Digital infrastructure is an important part of maintaining Eni's operations. A breach of Eni's digital security could result in serious damage to business operations, personal injury, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs

The reliability and security of Eni's digital infrastructure is critical to maintaining the availability of Eni's business applications, including the reliable operation of technology in Eni's various business operations and the collection and processing of financial and operational data, as well as the confidentiality of certain third-party information. If Eni's systems for protecting Eni's digital security prove to be ineffective, either due to intentional actions such as cyber-attacks or negligence, Eni could be adversely affected by, among other things, loss or damage to intellectual property, proprietary information, or customer data, an interruption of business operations, and increased costs to prevent, respond to, or mitigate potential risks to Eni's digital infrastructure. Furthermore, in some circumstances, failures to protect digital infrastructure could result in injury to people, damage to assets, harm to the environment, breaches of regulations, litigation, legal liabilities and reparation costs.

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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. In 2016, the Group exited the Engineering & Construction segment by divesting an interest of 12.503% in the segment parent company, Saipem. Simultaneously to that divestment the Group signed a shareholder agreement with the acquirer that established joint control over Saipem. As a result of those transactions, Eni derecognized Saipem's assets and liabilities, revenues and expenses effective January 1, 2016. The retained interest of 30.55% in Saipem has been accounted for as an equity-accounted investment from the transactions date. Eni has operations in 73 countries and 33.536 employees as of December 31, 2016.

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 44 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Ghana and Mozambique. In 2016, Eni average daily production amounted to 1,671 KBOE/d on an available-for-sale basis. As of December 31, 2016, Eni's total proved reserves amounted to 7,490 mmBOE, which include subsidiary undertakings and Eni's share of reserves of equity-accounted 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 2016, Eni's worldwide sales of natural gas amounted to 88.93 BCM, of which 38.43 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, 2016. In 2016, electricity sold totaled 37.05 TWh. The Gas & Power segment comprises results of the Group activities intended to manage commodity risk and of asset-backed trading activities. Through the trading department of the parent company and its wholly-owned subsidiary Eni Trading & Shipping SpA, the Group engages in derivative activities targeting the full spectrum of energy commodities on both the physical and financial trading venues. This activity is designated to hedge part of the Group exposure to the commodity risk and to optimize commercial margins by entering speculative derivative transactions. Furthermore, this activity includes the result of crude oil and products supply, trading and shipping.

Eni's Refining & Marketing segment 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. In 2016, processed volumes of crude oil and other feedstock, including renewable feedstock, amounted to 24.73 mmtonnes (of which traditional refinery throughputs were 24.52 mmtonnes and green refinery throughputs were 0.21 mmtonnes) and sales of refined products were 33.41 mmtonnes, of which 25.6 mmtonnes in Italy. Retail sales of refined products at Eni's service stations amounted to 8.59 mmtonnes in Italy and in the rest of Europe. In 2016, Eni's retail market share in Italy through its "Eni" branded network of service stations was 24.3%.

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Through its wholly-owned subsidiary Versalis, the Group engages in the production and marketing of basic petrochemical products, plastics and elastomers. Activities are concentrated in Italy and in Europe. The four-year industrial plan foresees the start-up of joint ventures for the production of elastomers in East Asia. In 2016, production volumes of petrochemicals amounted to 5,646 Ktonnes.

The results of Versalis have been aggregated with those of R&M, in the reportable segment "R&M and Chemicals" because the two segments 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 48 – Other information about investments – of the Notes on Consolidated Financial Statements".

Strategy

Eni's strategy is reflective of a deteriorated commodity price environment. During the oil downturn, we have managed to be more selective in our capital investment decisions, to dispose of non-strategic assets, to boost efficiency across all business lines, to renegotiate contracts, to right-size refinery and chemical plants capacity and to streamline processes, operations and G&A. In 2016, we reduced our capital expenditure by 19% y-o-y, mainly in our E&P segment with negligible impacts on our production levels. In spite of the severity of the oil price contraction, which has lost about two thirds of its value from its highs in 2014 compared to the average value registered in 2016, the ratio of net borrowings to total shareholders' equity, including non-controlling interests, was 0.28 at 2016 year-end below the management 0.3 ceiling. For further information see "Item 5 – Liquidity."

Our priority in the next few years is to increase cash-flow generation, through growing profitably in E&P and enhancing our mid and downstream businesses. We will continue to focus on capital discipline, effective management of the time-to-market of our reserves, early monetization of discovered resources through the disposal of interests in exploration assets and cost control. Our four-year plan foresees a capital budget of approximately €31.6 billion, which is 8% lower than the previous plan, while we are revising upwardly our long-term Brent price assumptions to 70 $/barrel, up from a previous 65 $/barrel. This capital budget is reflective of our cautious stance about future trends in the oil market. Going forward, we will retain a low level of cash neutrality, i.e. we have identified actions and initiatives which should enable the Company to fund its planned capital expenditures via cash flow from operations in a low Brent price environment. Our key financial objectives are disclosed under "Item 5 – Management's expectations of operations".

Our strategic guidelines are described below.

- In the Exploration & Production segment, we plan to achieve profitable production growth to boost cash generation. New field start-ups, ramp-ups at our current field and production optimization to fight natural depletion will underpin our production targets at 2020. Exploration will be the main driver of our future growth and reserve replacement. It will also boost cash generation through early monetization of discovered resources, as it was the case with the Zohr 40% divestment, which is expected to be completed in 2017. Phased project development, designed to reduce financial exposure and fasten production start-up, effective management of the time-to-market of our capital projects and cost control will sustain cash generation.

- In the Gas & Power, R&M and Chemicals segments, our priority is to retain profitable and cash-generative operations against the backdrop of structural headwinds in the competitive environment due to expectations of sluggish trends in commodity demand, strong competition and oversupplies/overcapacity. The achievement of this goal will require continued initiatives of business enhancement and improvement.

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In executing this strategy, management intends to pursue integration opportunities among segments, and within each segment to focus strongly on efficiency improvement through technology upgrading, cost efficiencies, commercial and supply optimization and continuing process streamlining across all segments.

Finally, we are reaffirming our commitment to a progressive dividend policy, in line with our plans of underlying earnings and cash flow growth and the scenario evolution.

For a description of risks and uncertainties associated with the Company's outlook and the capital expenditure program see "Item 5 – Operating and financial review and prospects – Management's expectations of operations".

Significant business and portfolio developments

The significant business and portfolio developments that occurred in 2016 and to date in 2017 were the following:

- Eni signed two preliminary agreements with Bp and Rosneft for the disposal of a 40% interest in the important gas Zohr discovery, located in the operated block of Shoruk (Eni's interest 100%) off Egypt. These transactions confirm the effectiveness of Eni's "dual exploration model", which simultaneously targets the fast-track development of discovered resources, while reducing stakes retained in exploration leases in order to monetize in advance part of the discovered volumes and reduce expenditures in development process. These agreements have economic efficacy from January 1, 2016 and contemplate the reimbursement to Eni of capex incurred until the closing date. The new partners have the option to acquire a further 5% stake at the same terms defined in the agreements. The first transaction closed on February 2017 following approval by the Egyptian authorities; the second one with Rosneft is expected to close by the first half of 2017. The total consideration of the deal amounts to approximately €2 billion as of January 1, 2017, including the reimbursement of costs incurred by Eni in 2016.

- March 2017: Eni and Gazprom signed a Memorandum of Understanding aiming to analyze the prospects for cooperation in developing the Southern corridor for gas supplies from Russia to European countries, including Italy, as well as the updating of the Russia-Italy gas supply agreements. The Memorandum also provides for the analysis of partnerships in the LNG sector.

- March 2017: Eni and ExxonMobil signed a sale and purchase agreement to acquire a 25% indirect interest in the Area 4 block, offshore Mozambique. Eni currently holds a 50% indirect interest in the block through a 71.4% stake in Eni East Africa, which is operator of the Area 4 concession with a 70% interest. The agreed terms include a cash price of approximately $2.8 billion. The acquisition will be completed subject to satisfaction of certain conditions precedent, including clearance from Mozambican and other regulatory authorities. Following completion of the transaction, Eni East Africa will be co-owned by Eni and ExxonMobil with a 35.7% stake and the remaining interest of 28.6% by and CNPC. Eni will continue to lead the Coral Floating LNG project and all upstream operations in Area 4, while ExxonMobil will lead the construction and operation of natural gas liquefaction facilities onshore. This operating model will enable the use of best practices and skills within Eni and ExxonMobil with each company focusing on distinct and clearly defined scopes while preserving the benefits of a fully integrated project.

- March 2017: finalized a farm-in agreement to acquire a 50% interest of Block 11, Offshore Cyprus, which will be operated by Total. The exploration area covers 2,215 square kilometers, nearby the Zohr discovery in the Egyptian offshore. Block 11 is expected to be drilled within 2017.

- February 2017: started-up the Cabaça South East field of the East Hub Development Project, in Block 15/06 of the Angolan deep offshore, five months ahead of development plan estimates and with a very good time-to-market. Block 15/06 will reach a peak of 150 KBBL/d this year.

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January 2017: successfully drilled an appraisal well of the Merakes discovery under the Production Sharing Contract (PSC) in East Sepinggan. This discovery is located 35 kilometers from the Eni operated Jangkrik field, close to starting operations.

- January 2017: made a discovery in the PL128/128D licenses in the Norwegian Sea nearby the FPSO (Floating Production, Storage and Offloading) operating the Norne field. This discovery is part of Eni's near-field exploration strategy aimed at unlocking the presence of additional resources in proximity to existing infrastructures.

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- January 2017: awarded three new exploration licenses in Norway, as a part of the APA Round.

- January 2017: signed a Memorandum of Understanding with the Nigerian Authorities for the development of the mineral potential of the Country. The agreement also comprises the upgrading of the Port Harcourt refinery and a capacity doubling of the power generation unit in Okpai IPP.

- November 2016: signed four agreements in Bahrein with the National Oil Companies for the evaluation of the mineral potential of certain exploration areas and for the study of the Awali fields.

- October 2016: signed a binding agreement between the partners of the Area 4 in Mozambique (Eni East Africa, joint operation between Eni and CNPC, Galp, Kogas and ENH) and BP for the sale, over a 20-year period, of approximately 3.3 million tons of LNG per annum (corresponding to about 5 BCM), which will be produced at the Coral South Floating facility. The agreement, approved by the Government of Mozambique, is a fundamental step towards achieving the Final Investment Decision (FID) of the project. The achievement of the FID is prerequisite to the efficacy of the sale contract. Back in February 2016, the Mozambique authorities approved the first development phase of Coral, targeting production of 5 trillion cubic feet (TCF) of gas.

- October 2016: restarted production at the Kashagan field with the completion of works to fully replace the damaged pipelines following the gas leak occurred at the end of 2013. The production of 180 KBOE/d was achieved by year-end. The production capacity of 370 KBBL/d planned for the Phase 1 is expected to be achieved during 2017, when gas reinjection comes online.

- September 2016: as part of Eni’s “near-field” exploration strategy, activities resumed onshore Tunisia with the Larich East discovery. The well has been put into production by linking the discovery well to the MLD oil treatment center.

- September 2016: reached a production plateau of 700 mmCF/d (corresponding to 128 KBOE/d, 67 KBOE/d net to Eni) from the Nooros field. This record-setting production level was reached in just 13 months after the discovery and ahead of schedule, thanks to the success of the latest exploration wells drilled in the Nooros area and the drilling of new development wells. In addition, thanks to the mature operating environment and the conventional nature of the project, production costs are among the lowest in Eni’s portfolio.

- September 2016: the potential at the Baltim South West field discovery, in the conventional water of Egypt, was upped due to successful test of the first appraisal well. The discovery is located near the Nooros field.

- September 2016: successfully drilled the Zohr 5x appraisal well, located in 1,538 meters of water depth and 12 kilometers south west from the discovery well. The appraisal well confirmed the overall potential of the Zohr Field. The Zohr development was sanctioned by Egyptian authorities in February 2016. Expected the drilling of a sixth well that will accelerate the production start-up within the end of 2017.

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March 2016: production start-up at the Goliat oilfield, which is the first producing oilfield in the Barents Sea in the license PL229. Goliat is operated through floating cylindrical production and storage vessel (FPSO). Production has achieved the full-field plateau at 100 KBBL/d (65 KBBL/d net to Eni).

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In 2016, Eni increased its exploration rights portfolio by about 10,500 square kilometers net, mainly in Egypt, Ghana, Morocco, Montenegro, Norway and the United Kingdom.

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As part of its strategy designed to evolve the Company's business model towards a low-carbon environment, Eni intends to develop renewable energy projects in its countries of operations. In 2016, Eni selected and launched a number of industrial initiatives on a large scale in Italy and abroad: (i) The "Italy project" plans to build facilities, mainly in the solar photovoltaic business, in owned industrial areas, which are ready to use and currently lack any industrial value. Fifteen projects have been identified with an overall capacity of approximately 220 MW to be installed by 2022. The first phase of the project foresees the installation of five units: Assemini and Porto Torres in Sardinia (obtained the Final Investment Decision for both projects, while the approval is ongoing from the relevant authorities), Monte Sant'Angelo in Puglia and Priolo in Sicily (FID obtained) and finally Augusta in Sicily; (ii) Outside Italy the company has identified a number of projects to be deployed in countries of operations considered strategic for the Company (mainly Africa and Asia) to increase Eni's energy efficiency, the sustainability of our consumptions, as well as to improve the access to energy of local communities through a more sustainable energy mix. In December 2016 Eni obtained the FID for a development project in the upstream field BRN in Algeria. Furthermore, a number of agreements for collaboration have been settled with Ghana, Algeria and Tunisia, to strengthen Eni's presence in these countries and to enlarge the

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scope of activities. Finally, in 2016 Eni signed strategic framework agreements with: (i) General Electric (GE) for the development of innovative technologies on renewable energy projects (brownfield and greenfield) and hybrid renewable projects focused on energy efficiency. This agreement is intended to identify and develop jointly projects for power generation from renewable sources on large scale; (ii) Terna, Italian grid operator for electricity transmission, for the evaluation of opportunities for the development of energy systems with a focus on sustainability and supporting production from renewables.

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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 44 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Ghana and Mozambique. In 2016, Eni average daily production amounted to 1,671 KBOE/d on an available-for-sale basis. As of December 31, 2016, Eni's total proved reserves amounted to 7,490 mmBOE; proved reserves of subsidiaries totaled 6,613 mmBOE; Eni's share of reserves of equity-accounted entities stood to 877 mmBOE.
Eni's strategy in its Exploration & Production operations is to pursue profitable production growth by developing its portfolio of projects underway and by optimizing its current producing fields. We plan to achieve a production growth rate of 3% on average post disposals in the next 2017-2020 four-year period. Our production plans are incorporating our Brent price scenario of 55$/BBL in 2017 and a gradual recovery in the subsequent years up to our long-term case of 70$/BBL in 2020 and going forwards (on constant monetary term compared to 2020, i.e. from 2021 onwards crude oil prices will grow in line with a projected inflationary rate); as well as certain other trading environment assumptions including an indication of Eni's production volume sensitivity to oil prices which are disclosed under "Item 5 – Management's expectations of operations"
Management plans to achieve the target production growth by continuing development activities and new project start-ups in the main areas of operations including, North Africa, Sub-Saharan Africa and the Far East, leveraging Eni's vast knowledge of reservoirs and geological basins, as well as technical and producing synergies. New field start-ups, production ramp-ups and continuing production optimization will add approximately 850 KBOE/d in 2020; over 60% of these new projects have already been sanctioned and Eni is operator in approximately 70%.
Management plans to maximize the production recovery rate at our current fields by counteracting natural field depletion and reducing facilities downtime. This will require intense development activities of work-over and infilling and careful planning of maintenance activities. We expect that continuing technological innovation and competence build-up will drive increasing rates of reserve recovery.
Management plans to invest some €27.1 billion to explore for and to develop reserves over the next four years, with a decrease of 13% net of exchange rate effects versus the previous four-year plan to mitigate the impact of a low oil price environment and net of planned disposal. We plan to prioritize lower intensity projects, brown-field developments and infilling wells mainly in Egypt, Libya and Algeria, while we plan to re-schedule spending in some large projects. This re-scheduling will account for half of the overall reduction, while the remaining will be determined by contracts renegotiations.
Planned expenditures in exploration are expected to be some €2.1 billion, slightly lower than the previous four-year plan. Exploration expenditure will be focused on proven plays, near field and appraisal exploration, where we plan to drill 50% of our scheduled wells in 2017-2018. Management planned to progressively increase activity in high-risk high-rewards targets, retaining large stakes in those initiatives with a view of implementing Eni's dual exploration model.
Management intends to implement a number of initiatives to support profitability in its upstream operations by exercising tight control on project time schedules and costs and reducing the time span, which is necessary to develop and market reserves. We plan to achieve efficient development of our reserves by: (i) in-sourcing critical engineering and project management activities also redeploying to other areas key competences, which will be freed with the start-up of certain strategic projects and increase direct control and governance on construction and commissioning activities; and (ii) signing framework agreements with major suppliers, using standardized specifications to speed up pre-award process for critical equipment and plants, increasing focus on supply chain programming to optimize order flows. Based on those initiatives, we believe that almost all of our projects which we are currently developing over the next four years will be completed on time and on budget.
Finally we plan to achieve further cost efficiencies by: (i) increasing the scale of our operations as we concentrate our resources on larger fields than in the past where we plan to achieve economies of scale;

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(ii) expanding projects where we serve as operator. We believe operatorship will enable the Company to exercise better cost control, effectively manage reservoir and production operations, and deploy our safety standards and procedures to minimize risks; (iii) applying our technologies which we believe can reduce drilling and completion costs; and (iv) renegotiating contracts for oilfield services and other items to reap the benefits of the deflationary trend in the industry.

We plan to mitigate the operational risk relating to drilling activities by applying Eni's rigorous procedures throughout the engineering and execution stages, by leveraging on proprietary drilling technologies, excellent skills and know-how, increased control of operations and by deploying technologies which we believe to be able to reduce blow-out risks and to enable the Company to respond quickly and effectively in case of emergencies.

For the year 2017, management plans to spend over €6 billion in reserves development and exploration projects, net of planned disposals.

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 buy-back and 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 entrusted with the task 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.

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Company guidelines have been reviewed by DeGolyer and MacNaughton (D&M), an independent petroleum engineering company, which has 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 at the head office verifies the production profiles of such properties where significant changes have occurred; (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 25 years of experience in the oil&gas industry and more than 15 years of experience in evaluating reserves.

Staff involved in the reserves evaluation process fulfils the professional qualifications requested and maintains the highest 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

Since 1991, Eni has requested qualified independent oil engineering companies to carry out an independent evaluation(2) of part of its proved reserves on a rotational basis. 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 economic 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 2016, Ryder Scott Company, DeGolyer and MacNaughton and Gaffney, Cline & Associates provided an independent evaluation of approximately 41% of Eni’s total proved reserves at December 31, 2016(4), confirming, as in previous years, the reasonableness of Eni internal evaluation(5).

In the 2014-2016 three-year period, 94% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2016, the main Eni properties, which did not undergo an independent evaluation in the last three years, were Zubair (Iraq), Bu Attifel (Libya) and CAFC-MLE (Algeria).

(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 and from 2015, also Gaffney, Cline & Associates.

(3)
See “Item 19 – Exhibits”.

(4)

Includes Eni’s share of proved reserves of equity-accounted entities.

(5)
See “Item 19 – Exhibits”.

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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, 2016, 2015 and 2014. Net proved reserves are set out in more detail under the heading “Supplemental oil and gas information” on page F-147.

HYDROCARBONS

(mmBOE)

	Italy	Rest of Europe	North Africa	of which Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Year ended Dec. 31, 2014	503	544	1,740		1,239	1,069	285	232	160	5,772
developed	401	335	904		702	589	112	188	135	3,366
undeveloped	102	209	836		537	480	173	44	25	2,406
Year ended Dec. 31, 2015	465	495	1,694		1,282	1,198	422	269	150	5,975
developed	362	404	1,010		764	689	159	217	115	3,720
undeveloped	103	91	684		518	509	263	52	35	2,255
Year ended Dec. 31, 2016	354	426	2,432	1,293	1,317	1,221	491	227	145	6,613
developed	287	374	957	352	809	966	175	205	111	3,884
undeveloped	67	52	1,475	941	508	255	316	22	34	2,729
Equity-accounted entities										
Year ended Dec. 31, 2014			16		81		5	728		830
developed			15		23		3	26		67
undeveloped			1		58		2	702		763
Year ended Dec. 31, 2015			14		87		4	810		915
developed			14		22		2	265		303
undeveloped					65		2	545		612
Year ended Dec. 31, 2016			14		82		2	779		877
developed			14		26		2	349		391
undeveloped					56			430		486
Consolidated subsidiaries and equity accounted entities										
Year ended Dec. 31, 2014	503	544	1,756		1,320	1,069	290	960	160	6,602

developed	401	335	919		725	589	115	214	135	3,433
undeveloped	102	209	837		595	480	175	746	25	3,169
Year ended Dec. 31, 2015	465	495	1,708		1,369	1,198	426	1,079	150	6,890
developed	362	404	1,024		786	689	161	482	115	4,023
undeveloped	103	91	684		583	509	265	597	35	2,867
Year ended Dec. 31, 2016	354	426	2,446	1,293	1,399	1,221	493	1,006	145	7,490
developed	287	374	971	352	835	966	177	554	111	4,275
undeveloped	67	52	1,475	941	564	255	316	452	34	3,215

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LIQUIDS
(mmBBL)

	Italy	Rest of Europe	North Africa	of which Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Year ended Dec. 31, 2014	243	331	776		739	697	131	147	13	3,077
developed	184	174	521		470	306	64	116	12	1,847
undeveloped	59	157	255		269	391	67	31	1	1,230
Year ended Dec. 31, 2015	228	305	821		787	771	262	189	9	3,372
developed	171	237	542		511	355	126	149	9	2,100
undeveloped	57	68	279		276	416	136	40		1,272
Year ended Dec. 31, 2016	176	264	735	281	809	767	307	163	9	3,230
developed	132	228	492	205	507	556	124	143	8	2,190
undeveloped	44	36	243	76	302	211	183	20	1	1,040
Equity-accounted entities										
Year ended Dec. 31, 2014			14		17		1	117		149
developed			13		7			26		46
undeveloped			1		10		1	91		103
Year ended Dec. 31, 2015			13		16			158		187
developed			13		6			29		48
undeveloped					10			129		139
Year ended Dec. 31, 2016			13		15			140		168
developed			13		8			22		43
undeveloped					7			118		125
Consolidated subsidiaries and equity accounted entities										
Year ended Dec. 31, 2014	243	331	790		756	697	132	264	13	3,226
developed	184	174	534		477	306	64	142	12	1,893
undeveloped	59	157	256		279	391	68	122	1	1,333
Year ended Dec. 31, 2015	228	305	834		803	771	262	347	9	3,559

developed	171	237	555		517	355	126	178	9	2,148
undeveloped	57	68	279		286	416	136	169		1,411
Year ended Dec. 31, 2016	176	264	748	281	824	767	307	303	9	3,398
developed	132	228	505	205	515	556	124	165	8	2,233
undeveloped	44	36	243	76	309	211	183	138	1	1,165

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NATURAL GAS (BCF)

	Italy	Rest of Europe	North Africa	of which Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries										
Year ended Dec. 31, 2014	1,432	1,171	5,291		2,744	2,049	846	468	807	14,808
developed	1,192	887	2,110		1,271	1,553	261	393	675	8,342
undeveloped	240	284	3,181		1,473	496	585	75	132	6,466
Year ended Dec. 31, 2015	1,304	1,044	4,798		2,714	2,354	878	439	771	14,302
developed	1,051	919	2,566		1,390	1,830	185	373	585	8,899
undeveloped	253	125	2,232		1,324	524	693	66	186	5,403
Year ended Dec. 31, 2016	977	878	9,258	5,520	2,767	2,485	1,003	353	741	18,462
developed	845	801	2,531	799	1,651	2,239	280	338	559	9,244
undeveloped	132	77	6,727	4,721	1,116	246	723	15	182	9,218
Equity-accounted entities										
Year ended Dec. 31, 2014			15		351		18	3,353		3,737
developed			15		89		10	6		120
undeveloped					262		8	3,347		3,617
Year ended Dec. 31, 2015			13		387		12	3,581		3,993
developed			13		85		9	1,295		1,402
undeveloped					302		3	2,286		2,591
Year ended 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										
Year ended Dec. 31, 2014	1,432	1,171	5,306		3,095	2,049	864	3,821	807	18,545
developed	1,192	887	2,125		1,360	1,553	271	399	675	8,462
undeveloped	240	284	3,181		1,735	496	593	3,422	132	10,083
Year ended Dec. 31, 2015	1,304	1,044	4,811		3,101	2,354	890	4,020	771	18,295

developed	1,051	919	2,579		1,475	1,830	194	1,668	585	10,301
undeveloped	253	125	2,232		1,626	524	696	2,352	186	7,994
Year ended Dec. 31, 2016	977	878	9,273	5,520	3,135	2,485	1,007	3,837	741	22,333
developed	845	801	2,546	799	1,755	2,239	284	2,120	559	11,149
undeveloped	132	77	6,727	4,721	1,380	246	723	1,717	182	11,184

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 212 mmBOE as of December 31, 2016 (139 and 282 mmBOE as of December 31, 2015 and 2014, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			Equity-accounted entities		
	2014	2015	2016	2014	2015	2016
	(mmBOE)					
Additions to proved reserves	643	849	1,254	11	98	(10)
Purchases of minerals-in-place	4					
Sales of minerals-in-place	(8)	(17)				
Production for the year (a)	(575)	(629)	(616)	(8)	(13)	(28)

(a)
The difference over production sold of 608.6 mmBOE (549.5 mmboe in 2014 and 642.4 mmboe in 2015) reflected natural gas volumes of 32.1 mmBOE consumed in operations (29.4 mmBOE in 2014 and 26.4 mmBOE in 2015), changes in inventories and other factors.

	Subsidiaries and equity-accounted entities		
	2014	2015	2016
	(%)		
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	112	145	193
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, organic	112	148	193

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Eni's proved reserves as of December 31, 2016 totaled 7,490 mmBOE (liquids 3,398 mmBBL; natural gas 22,333 BCF). Eni's proved reserves reported an increase of 600 mmBOE, or 8.7%, from December 31, 2015. All sources additions to proved reserves booked in 2016 were 1,244 mmBOE; of which 1,254 mmBOE came from Eni's subsidiaries and negative from Eni's share of equity-accounted entities.

Due to a lowered Brent price at $42.8 per barrel in 2016 ($54 per barrel in 2015), our all sources additions were adversely affected by a downward revision of 76 mmBOE, due to our having to remove certain volumes of reserves which have become uneconomical in that environment, which were partially offset by higher volume entitlements at our PSA contracts because of the cost recovery mechanism. 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 – Risk associated with the exploration and production of oil and natural gas".

The methods (or technologies) used in the Eni's proved reserves assessment in 2016 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 achieved by Eni's subsidiaries and equity-accounted entities was 193% in 2016 (145% in 2015 and 112% in 2014).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 11.6 years as of December 31, 2016, which included reserves of both subsidiaries and equity-accounted entities.

Eni's subsidiaries

Eni's subsidiaries added 1,254 mmBOE of proved oil&gas reserves in 2016. This comprised 173 mmBBL of liquids and 5,808 BCF of natural gas. Additions to proved reserves derived from: (i) extensions and discoveries were 887 mmBOE, with major increase booked in Egypt following the final investment decision of the Zohr gas project; (ii) revisions of previous estimates were 365 mmBOE mainly reported in Libya, Iraq and Kazakhstan due to continuous development activities and field performances; and (iii) improved recovery were 2 mmBOE mainly reported in Algeria and Norway.

Eni's share of equity-accounted entities

Additions in Eni's share of equity-accounted entities' proved oil&gas were negative in 2016 and derived from downward revisions of previous estimates reported in Americas.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2016 totaled 3,215 mmBOE. At year-end, proved undeveloped reserves of liquids amounted to 1,165 mmBBL, mainly concentrated in Africa. Proved

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undeveloped reserves of natural gas amounted to 11,184 BCF, mainly located in Africa and Americas. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,040 mmBBL of liquids and 9,218 BCF of natural gas.

In 2016, total proved undeveloped reserves increased by 348 mmBOE mainly due to: (i) extensions and discoveries (up by 873 mmBOE), in particular in Egypt due to final investment decision sanctioned for the Zohr discovery; (ii) revisions of previous estimates (up by 121 mmBOE) mainly reported in Congo and Iraq; (iii) reclassification to proved developed reserves (down by 646 mmBOE).

During 2016, Eni converted 646 mmBOE of proved undeveloped reserves to proved developed reserves due to the progress of development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Kashagan (Kazakhstan), Perla (Venezuela), Litchendjili (Congo), Zubair (Iraq) and Goliat (Norway).

In 2016, capital expenditure amounted to approximately €7.5 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. Of the proved undeveloped reserves that have been reported for five or more years, the largest are related to forthcoming development phases of the Kashagan project in Kazakhstan (approximately 0.2 BBOE) and certain assets in Venezuela (approximately 0.4 BBOE) and in Iraq (approximately 0.2 BBOE), as well as to certain Libyan gas fields (approximately 0.5 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 fulfilment of the contractual delivery quantities in Libya, 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 regarding risks associated with oil&gas development projects).

Eni remains strongly committed to put these projects into production over the next few years. The length of the development period is a function of 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 453 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Libya, Nigeria, Norway and Venezuela.

The sales contracts contain a mix of fixed and variable pricing formulas that are generally referenced 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 86% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2016.

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

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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 2016, oil and natural gas production available for sale averaged 1,671 KBOE/d (1,688 KBOE/d in 2015) decreased by 1.0% from 2015, mainly due to the production shutdown in the Val d'Agri profit center (See also – oil and gas properties – Italy described above) as well as planned facilities downtime, mainly in the United Kingdom, and the mature fields declines. These negatives were partially offset by new field start-ups and the continuing ramp-up of production at fields started in 2015, mainly reported in Angola, Egypt, Kazakhstan, Norway and Venezuela as well as higher production in Iraq and the price effects reported in PSA contracts. New field start-ups and ramp-ups of production added an estimated 280 KBOE/d of new production.

Liquids production (878 KBBL/d) decreased by 30 KBBL/d, or 3.3%, due to the production shutdown in the Val d'Agri profit center, planned facilities downtime and the mature fields decline. These negatives were partially offset by new fields start-up and production ramp-up in particular in Angola, Kazakhstan and Norway as well as higher production in Iraq.

Natural gas production (4,329 mmCF/d) reported an increase of 45 mmCF/d, or 1.1% from 2015. Higher production in Egypt and Venezuela were partially offset by planned facilities downtime and the decline of mature fields.

Oil and gas production sold amounted to 608.6 mmBOE. The 3.4 mmBOE difference over production on an available-for-sale basis (612 mmBOE) reflected mainly changes in inventories and other factors. Approximately 68% of liquids production sold (320 mmBBL) was destined to Eni's mid-downstream sectors. About 22% of natural gas production sold (1,574 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 geographical area of each of the last three fiscal years.

2014 Production available for sale (a)		Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	171	184	528	305	85	87	112	25	1,497
	(mmBOE)	63	67	193	111	31	31	41	9	546
Eni share of equity-accounted entities	(KBOE/d)			4	2		4	10		20
	(mmBOE)			1	1		2	4		8
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	73	93	249	230	52	36	74	6	813
	(mmBBL)	27	34	91	84	19	13	27	2	297
Eni share of equity-accounted entities	(KBBL/d)			4			1	10		15
	(mmBBL)			1				4		5

Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	541	498	1,533	411	181	279	205	106	3,754
	(BCF)	198	182	559	150	66	102	75	39	1,371
Eni share of equity-accounted entities	(mmCF/d)			3	7		18			28
	(BCF)			1	3		6			10

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 442 mmCF/d or 29.4 mmBOE.

2015 Production available for sale (a)		Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	161	179	631	324	92	123	120	25	1,655
	(mmBOE)	59	65	230	119	33	45	44	9	604
Eni share of equity-accounted entities	(KBOE/d)			4			5	24		33
	(mmBOE)			1			2	9		12
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	69	85	268	256	56	77	75	5	891
	(mmBBL)	25	31	98	93	20	28	28	2	325
Eni share of equity-accounted entities	(KBBL/d)			4			1	12		17
	(mmBBL)			1			1	4		6
Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	503	515	1,990	378	199	259	243	107	4,194
	(BCF)	183	188	727	138	73	94	89	39	1,531
Eni share of equity-accounted entities	(mmCF/d)			3			19	68		90
	(BCF)			1			7	25		33

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 397 mmCF/d or 26.4 mmBOE.

2016 Production available for sale (a)		Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	127	195	608	312	107	114	114	23	1,600
	(mmBOE)	47	71	222	114	39	42	42	8	585
	(KBOE/d)			3	4		4	60		71

Eni share of equity-accounted entities										
	(mmBOE)			1	2		2	22		27
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	47	109	241	247	65	78	69	3	859
	(mmBBL)	17	40	88	91	24	28	25	1	314
Eni share of equity-accounted entities	(KBBL/d)			3	1		1	14		19
	(mmBBL)			1			1	5		7
Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	436	468	2,000	353	234	199	243	110	4,043
	(BCF)	159	171	732	129	86	73	89	40	1,479
Eni share of equity-accounted entities	(mmCF/d)			3	16		15	252		286
	(BCF)			1	6		6	92		105

(a)
It excludes production volumes of natural gas consumed in operations. Said volumes were 478 mmCF/d or 32.1 mmBOE.

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 56 KBOE/d, 84 KBOE/d and 78 KBOE/ d in 2016, 2015 and 2014, 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. Also Eni subsidiaries and its equity-accounted entities' average production cost per unit of production are provided. The average production cost does not include any ad valorem or severance taxes.
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AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT OF PRODUCTION

($)	Italy	Rest of Europe	North Africa	of which Egypt	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2014										
Consolidated subsidiaries										
Oil and condensates, per BBL	87.80	88.80	88.99		93.45	91.86	77.99	79.13	91.61	88.90
Natural gas, per KCF	8.74	8.49	8.08		2.12	0.62	6.18	3.96	7.46	6.83
Average production cost, per BOE	15.19	13.61	6.79		18.88	8.94	10.70	11.75	20.14	12.00
Equity-accounted entities										
Oil and condensates, per BBL			17.94				65.90	81.48		70.56
Natural gas, per KCF			6.08				15.64			14.13
Average production cost, per BOE			12.50				9.79	42.27		26.18
2015										
Consolidated subsidiaries										
Oil and condensates, per BBL	43.46	45.88	46.66		49.91	48.26	40.10	43.36	45.84	46.46
Natural gas, per KCF	6.92	6.30	4.69		1.49	0.47	4.83	2.20	5.07	4.54
Average production cost, per BOE	11.08	10.93	5.72		14.08	7.93	6.48	11.61	14.49	9.18
Equity-accounted entities										
Oil and condensates, per BBL			18.03				27.89	38.18		35.15
Natural gas, per KCF			3.78				9.27	4.24		5.30
Average production cost,			8.98				8.67	16.48		14.51

per BOE										
2016										
Consolidated subsidiaries										
Oil and condensates, per BBL	33.19	39.97	39.43	33.05	41.92	39.61	36.89	34.86	37.96	39.33
Natural gas, per KCF	4.93	4.49	3.29	3.82	1.41	0.34	3.50	1.94	3.60	3.20
Average production cost, per BOE	9.69	9.31	4.89	6.34	12.09	7.58	6.14	8.70	7.08	7.79
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			9.74				8.19	8.81		8.34

Development activities

In 2016, a total of 296 development wells were drilled (118.7 of which represented Eni's share) as compared to 335 development wells drilled in 2015 (132.4 of which represented Eni's share) and 440 development wells drilled in 2014 (191 of which represented Eni's share). The drilling of 68 development wells (28.6 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, 2016. 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.

Development Well Activity

	Net wells completed						Wells in progress at 31 Dec.	
	2014		2015		2016		2016	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	12.5		6.0		4.0		1.0	1.0
Rest of Europe	9.8	1.0	10.2	0.1	5.6		4.0	0.6
North Africa	54.5	1.0	30.5	2.8	38.6	1.2	18.0	10.0
Sub-Saharan Africa	31.6		22.0	2.5	21.2	0.2	36.0	14.0
Kazakhstan	1.5		4.7		4.6	3.0	0.8	
Rest of Asia	54.2	1.6	29.7	5.9	31.6	0.5	2.0	0.3
Americas	22.1	0.7	17.4	0.1	9.9	1.3	4.0	1.9
Australia and Oceania	0.1	0.4	0.5					

Total including equity-accounted entities	186.3	4.7	121.0	11.4	115.5	3.2	68.0	28.6

Exploration activities

In 2016, a total of 16 new exploratory wells were drilled (10.2 of which represented Eni's share), as compared to 29 exploratory wells drilled in 2015 (19.1 of which represented Eni's share) and 44 exploratory wells drilled in 2014 (25.8 of which represented Eni's share).

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The overall commercial success rate was 50% (50% net to Eni) as compared to 16.7% (25.1% net to Eni) and 31.3% (38% net to Eni) in 2015 and 2014, 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, 2016. 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.

Exploratory Well Activity

	Net wells completed						Wells in progress at Dec. 31(1)	
	2014		2015		2016		2016	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy		0.6				1.0	4.0	2.3
Rest of Europe		4.3		2.2	0.1	0.4	9.0	2.3
North Africa	3.5	4.3	3.3	5.8	6.0	1.8	16.0	12.3
Sub-Saharan Africa	7.3	7.3	0.6	2.9	0.1	1.1	32.0	17.0
Kazakhstan							6.0	1.1
Rest of Asia	1.3	4.3		3.4		0.9	8.0	3.2
Americas	2.0	1.4	1.0	0.3		1.0	3.0	1.5
Australia and Oceania		0.9					1.0	0.3
Total including equity-accounted entities	14.1	23.1	4.9	14.6	6.2	6.2	79.0	40.0

(1)
Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

In 2016, Eni performed its operations in 44 countries located in five continents. As of December 31, 2016, Eni's mineral right portfolio consisted of 780 exclusive or shared rights of exploration and development activities for a total acreage of 323,896 square kilometers net to Eni of which developed acreage of 32,489 square kilometers and undeveloped acreage of 291,407 square kilometers net to Eni. In 2016, changes in total net acreage mainly derived from: (i) new leases mainly in Egypt, Ghana, Morocco, Montenegro, Norway and the United Kingdom for a total acreage of approximately 10,500 square kilometers; (ii) the total relinquishment of licenses mainly in Australia, Gabon, India, Liberia, Norway and the United States covering an acreage of approximately 13,000 square kilometers; and (iii) partial relinquishment in Australia, Portugal and South Africa or interest reduction mainly in Myanmar, for approximately 17,000 square kilometers.

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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, 2016. A gross acreage is one in which Eni owns a working interest.

	December 31, 2015	December 31, 2016						
	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	45,123	295	15,693	51,758	67,451	10,827	34,553	45,380
Italy	16,975	146	10,498	10,320	20,818	8,775	7,992	16,767
Rest of Europe	28,148	149	5,195	41,438	46,633	2,052	26,561	28,613
Cyprus	10,018	3		12,523	12,523		10,018	10,018
Croatia	987	2	1,975		1,975	987		987
Greenland	1,909	2		4,890	4,890		1,909	1,909
Montenegro		4		1,228	1,228		614	614
Norway	3,114	57	2,311	6,045	8,356	452	2,156	2,608
Portugal	6,370	3		4,547	4,547		3,182	3,182
United Kingdom	1,905	67	909	5,932	6,841	613	5,715	6,328
Other Countries	3,845	11		6,273	6,273		2,967	2,967
AFRICA	157,441	264	46,384	264,600	310,984	11,729	140,947	152,676
North Africa	25,699	121	14,292	54,122	68,414	5,738	23,654	29,392
Algeria	1,179	42	3,222	187	3,409	1,148	31	1,179
Egypt	9,668	57	5,508	22,523	28,031	2,074	8,591	10,665
Libya	13,294	11	1,962	24,673	26,635	958	12,336	13,294
Morocco		1		6,739	6,739		2,696	2,696
Tunisia	1,558	10	3,600		3,600	1,558		1,558
Sub-Saharan Africa	131,742	143	32,092	210,478	242,570	5,991	117,293	123,284
Angola	4,404	57	8,160	12,892	21,052	1,024	3,343	4,367
Congo	1,354	25	1,794	657	2,451	971	197	1,168
Gabon	7,615	4		6,217	6,217		6,217	6,217
Ghana	100	3		1,353	1,353		579	579
Ivory Coast	429	1		954	954		286	286
Kenya	40,426	7		61,363	61,363		41,173	41,173
Liberia	1,841	1		2,341	2,341		585	585
Mozambique	1,956	6		3,911	3,911		1,956	1,956
Nigeria	7,432	34	22,138	8,631	30,769	3,996	3,374	7,370
South Africa	32,881	1		65,696	65,696		26,279	26,279

Other Countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	117,183	59	18,165	198,024	216,189	6,016	103,745	109,761
Kazakhstan	869	6	2,391	2,542	4,933	442	427	869
Rest of Asia	116,314	53	15,774	195,482	211,256	5,574	103,318	108,892
China	7,069	8	77	7,056	7,133	13	7,056	7,069
India	6,167	1		13,110	13,110		5,244	5,244
Indonesia	25,124	14	4,246	30,243	34,489	1,603	23,578	25,181
Iraq	446	1	1,074		1,074	446		446
Myanmar	20,050	4		24,080	24,080		13,558	13,558
Pakistan	8,810	14	10,177	11,486	21,663	3,332	5,414	8,746
Russia	20,862	3		62,592	62,592		20,862	20,862
Timor Leste	1,230	1		1,538	1,538		1,230	1,230
Turkmenistan	180	1	200		200	180		180
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	6,628	148	4,948	8,154	13,102	3,208	2,488	5,696
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico	67	3		67	67		67	67
Trinidad & Tobago	66	1	382		382	66		66
United States	2,118	129	1,320	997	2,317	660	526	1,186
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other Countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	16,333	14	1,140	15,728	16,868	709	9,674	10,383
Australia	16,333	14	1,140	15,728	16,868	709	9,674	10,383
Total	342,708	780	86,330	538,264	624,594	32,489	291,407	323,896

(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.

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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, 2016. 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 9,399 (3,737.6 of which represent Eni's share).

Productive oil and gas wells at Dec. 31, 2016 (a)

(units)	Oil Wells		Natural gas Wells	
	Gross	Net	Gross	Net
Italy	243.0	197.1	616.0	532.4
Rest of Europe	395.0	72.5	160.0	88.1
North Africa	1,813.0	963.8	225.0	98.1
Sub-Saharan Africa	3,020.0	590.3	350.0	28.8
Kazakhstan	204.0	54.8		
Rest of Asia	727.0	479.1	1,036.0	393.2
Americas	264.0	133.3	321.0	98.5
Australia and Oceania	7.0	3.8	18.0	3.8
Total including equity-accounted entities	6,673.0	2,494.7	2,726.0	1,242.9

(a)
Multiple completion wells included above: approximateley 2,128 (741.9 net to Eni).

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 has been operating in Italy since 1926. In 2016, Eni's oil and gas production amounted to 127 KBOE/d. 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's exploration and development activities in Italy are regulated by concession contracts (50 operated onshore and 64 operated offshore) and exploration licenses (12 onshore and 9 offshore).

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The Adriatic and Ionian Seas represent Eni's main production area, accounting for 52% of Eni's domestic production in 2016. Main operated fields are Barbara, Cervia/Arianna, Annamaria, Luna, Angela-Angelina, Hera Lacinia, Bonaccia and Porto Garibaldi. Development activities concerned: (i) maintenance and production optimization, mainly at the Barbara, Cervia/Arianna and Morena fields; and (ii) start-up of the Clara NW development project.

Eni is the operator of the Val d'Agri concession (Eni's interest 60.77%) in the Basilicata Region in Southern Italy. Production from the Monte Alpi, Monte Enoc and Cerro Falcone fields is treated by the Viggiano oil center.

On August 12, 2016 the activity of the Val d'Agri Oil Centre in Viggiano gradually restarted following notification by the Italian Public Prosecutor of Potenza that has definitively repealed the plant seizure, with a four-month and half production shutdown, and by the National Mining Office for Hydrocarbons and Earth Resources of the Ministry of Economic Development that has authorized the plant's operation. The resumption of production is a result of the completion in June 2016 of certain plant upgrading, which do not alter the plant set up, authorized by the in-charge department of the Italian Ministry of Economic Development in order to address the alleged environmental crimes issued by the public prosecutor.

Eni operates 12 production concessions onshore and 3 offshore Sicily. The main fields are Gela, Ragusa, Tresauro, Giaurone, Fiumetto and Prezioso, which in 2016 accounted for approximately 12% of Eni's production in Italy.

Rest of Europe

Eni's operations in the Rest of Europe are conducted mainly in Croatia, Norway and the UK. In 2016, the Rest of Europe accounted for 12% of Eni's total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2016, Eni's production of natural gas averaged approximately 24 mmCF/d. Activities are deployed in the Adriatic Sea near the city of Pula.

Exploration and production activities in Croatia are regulated by PSAs.

The main producing gas fields are Annamaria, Ivana, Ika & Ida, Ika JZ, Ana, Marica and Katarina and are operated by Eni through a 50/50 joint operating company with the Croatian oil company INA.

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Norway. Eni has been operating in Norway since 1965. Eni's activities are performed in the Norwegian Sea, in the Norwegian section of the North Sea and in the Barents Sea. Eni's production in Norway amounted to 131 KBOE/d in 2016.

Exploration and production activities in Norway 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 currently holds interests in 10 production areas in the Norwegian Sea. The principal producing fields are Åsgard (Eni's interest 14.82%), Kristin (Eni's interest 8.25%), Heidrun (Eni's interest 5.17%), Mikkel (Eni's interest 14.9%), Tyrihans (Eni's interest 6.2%), Marulk (Eni operator with a 20% interest) and Morvin (Eni's interest 30%) which in 2016 accounted for 56% of Eni's production in Norway.

Eni holds interests in 2 production licenses in the Norwegian section of the North Sea. The main producing field is Ekofisk (Eni's interest 12.39%) in PL 018, which in 2016 produced approximately 16 KBOE/d net to Eni and accounted for 12% of Eni's production in Norway. The license expires in 2028, and negotiations are ongoing to grant an extension.

Eni holds interests in 17 exploration and development licenses in the Barents Sea, of which Eni operates 11 licenses. Operations have been focused on developing the Goliat discovery made in 2000 at a water depth of 370 meters in PL 229 (Eni operator with a 65% interest).

In March 2016, production start-up was achieved at the Goliat field (Eni operator with a 65% interest) in PL 229 and in 2016 accounted for 25% of Eni's production in Norway. Field production reached the target of 100 KBOE/d (65 KBOE/d net to Eni) and during the year peak production of approximately 114 KBOE/d (approximately 74 KBOE/d net to Eni) was achieved. The license expires in 2042.

Other development activities concerned: (i) the infilling activities in order to support production at the Ekofisk and Eldfisk in the PL 018; and (ii) the maintenance and optimization of the production at the Asgard (Eni's interest 14.82%), Heidrun (Eni's interest 5.17%) and Norne Outside (Eni's interest 11.5%) in the Norwegian Sea.

In 2016 Eni was awarded the following exploration licenses: (i) an 11.5% interest in the PL 128D in the Norwegian Sea; (ii) the operatorship and a 70% interest in the PL 816 in the Norwegian section of the North Sea; and (iii) the

operatorship and a 65% interest in the PL 229D and a 30% interest in the PL 849 in the Barents Sea.
In January 2017, Eni was awarded the PL 28E license (Eni's interest 11.5%) in the Norwegian Sea and the PL 900 (Eni operator with a 90% interest) and PL 901 (Eni's interest 30%) in the Barents Sea.
At the beginning of 2017, exploration activity yielded positive results with an oil and gas discovery in the PL 128/128D (Eni's interest 11.5%) in the Norwegian Sea, nearby production facilities of the Norne field (Eni's interest 6.9%).

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United Kingdom. Eni has been present in the UK since 1964. Eni's activities are carried out in the British section of the North Sea and the Irish Sea. In 2016, Eni's net production of oil and gas averaged 60 KBOE/d. Exploration and production activities in the UK are regulated by concession contracts.

Eni currently holds interests in 5 production areas of which the Liverpool Bay is operated by Eni with a 100% interest and Hewett Area is operated with an 89.3% interest. The other fields are Elgin/Franklin (Eni's interest 21.87%), J Block and Jasmine (Eni's interest 33%) and Jade (Eni's interest 7%), which in 2016 accounted for 63% of Eni's production in the UK.

The Phase 2 development activities of the West Franklin field (Eni's interest 21.87%) was completed and during the year peak production of 61 KBOE/d (13 KBOE/d net to Eni) was achieved.

Eni holds interest in 18 exploration licenses, of which 2 are partially in development, with interest ranging from 7% to 100%. Out of the total, 11 are operated by Eni.

In 2016, Eni was awarded the operatorship of PL2287, PL2288 and PL2292 licences with a 100% interest in the Irish Sea and Liverpool Bay area, nearby Eni operated production assets.

North Africa

Eni's operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2016, North Africa accounted for 37% of Eni's total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2016, Eni’s oil&gas production averaged 85 KBOE/d. Operated activities are located in the Bir Rebaa desert, in the Central-Eastern area of the country: (i) blocks 403a/d (Eni’s interest from 65% to 100%); (ii) block ROM North (Eni’s interest 35%); (iii) blocks 401a/402a (Eni’s interest 55%); (iv) block 403 (Eni’s interest 50%); (v) block 405b (Eni’s interest 75%); and (vi) block 212 (Eni’s interest 22.38%) with discoveries already made. In addition, Eni holds interest in the non-operated block 404 and block 208 with a 12.25% stake.
Exploration and production activities in Algeria are regulated by Production Sharing Agreements (PSAs) and concession contracts.
Production in blocks 403a/d and ROM North comes mainly from the HBN and ROM and satellites fields and represented approximately 21% of Eni’s production in Algeria in 2016.

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Production in blocks 401a/402a comes mainly from the ROD/SFNE and satellites fields and accounted for approximately 17% of Eni's production in Algeria in 2016. In 2016, Eni signed with the relevant Authorities a pre-unitization agreement of the SF-SFNE fields and a 10-year extension of the fields in the area. Development activities mainly concerned infilling and optimizations activities at the ROD field (Eni operator with a 66% interest).

The main fields in block 403 are BRN, BRW and BRSW, which accounted for approximately 9% of Eni's production in Algeria in 2016.

The main fields in block 404 are HBN and HBNS and satellites, which accounted for approximately 21% of Eni's production in Algeria in 2016.

Production in block 405b comes mainly from MLE and CAFC projects and accounted for approximately 13% of Eni's production in the country in 2016.

Production start-up was achieved at the CAFC oil project at the end of the year, with start-up of 6 wells and linkage at the treatment facilities of the area. The development activities are expected to complete during 2017.

Development and optimization activities progressed at the MLE and CAFC gas fields by means of construction and infilling activities, as well as production optimization.

The El-Merk field is the main production project in the block 208 and accounted for approximately 18% of Eni's production in Algeria in 2016.

Egypt. Eni has been present in Egypt since 1954. In 2016, Eni's share of production in this country amounted to 170 KBOE/d and accounted for 10% of Eni's total annual hydrocarbon production. Eni's main producing liquid fields are located in the Gulf of Suez, primarily the Belayim field (Eni's interest 100%), and in the Western Desert mainly the Melehia (Eni's interest 76%) and the Ras Qattara (Eni's interest 75%) concessions. Gas production mainly comes from the operated or participated concession of North Port Said (Eni's interest 100%), El Temsah (Eni's interest 50%), Baltim (Eni's interest 50%), Ras el Barr (Eni's interest 50%, non operated) and the Abu Madi West (Eni's interest 75%), located offshore the Nile Delta. In 2016, production from these large concessions accounted for approximately 98% of Eni's production in Egypt.

Exploration and production activities in Egypt are regulated by Production Sharing Agreements.

In February 2016, the Egyptian Ministry of Petroleum and Mineral Resources approved the award to Eni the Zohr Development Lease that allows the start-up of the development program at the Zohr gas field in the operated Shorouk concession (Eni's interest 100%) and, as a consequence, the FID was sanctioned and added proved undeveloped reserves for the field. The first gas is expected at the end of 2017. Based on the production test, delineation and development drilling activities management believes that this discovery contains a large amount of gas resources. Drilling activities will continue in 2017 together with construction activities of onshore gas treatment plant and offshore facilities installation.

In 2016, Eni signed two agreements to sell a 40% overall interest in the Shorouk concession. The agreements concerned the sale of: (i) a 10% interest to BP for a consideration amount of $375 million and the pro-quota reimbursement of past expenditures, which amount so far at approximately $150 million; and (ii) a 30% interest to Rosneft for a consideration amount of $1.125 million and the pro-quota reimbursement of past expenditures, which amount so far at approximately $450 million. In addition, the new partners have an option to buy a further 5% interest under the same terms.

In February 2017, Eni signed a deed completing the sale of 10% interest to BP, with all authorizations from Egypt's authorities. The sale agreement with Rosneft will be finalized in the first half of 2017 and subject to necessary authorizations from the country's authorities.

During the year targeting production of 85.5 KBOE/d net to Eni was achieved at the Nidoco NW field and satellites as a part of the Great Nooros Area project in the Abu Madi West concession. The start-up was achieved in 13 months following the announcement of the commercial discovery in July 2015 by means of the exploration successes in the Nooros area and the drilling of the new development wells. Production plateau of 160 KBOE/d is expected in 2017 with the completion of ongoing development activities.

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Other development activities concerned: (i) ongoing activity of the sub-sea END Phase 3 development project in the Ras El Barr concession (Eni's interest 50%) with the drilling and completion of two wells; (ii) infilling activities and production optimization at the Sinai 12 (Eni's interest 100%), Ashrafi (Eni's interest 25%) and Meleiha (Eni's interest 76%) concessions to support production capacity; (iv) start-up of the onshore gas treatment plant in the Meleiha concession.

In December 2016 Concession Agreements were ratified for the North El Hammad (Eni operator with a 37.5% interest) and North Ras El Esh (Eni's interest 50%) blocks, located in the conventional offshore of the Mediterranean Sea.

Exploration activity yielded positive results with the delineation drilling activity of the Baltim South West (Eni operator with a 50% interest), nearby the Great Nooros Area. Based on this ongoing activity management believes that this discovery contains an important gas resource.

In the medium term, management expects to increase Eni's production reflecting additions from ongoing development projects.

Libya. Eni started operations in Libya in 1959.

In recent years, Eni's production levels in Libya were negatively impacted by an internal revolution and a change of regime in 2011, which led to a prolonged period of political and social instability characterized by acts of local conflict, social unrest, protests, strikes and other similar events. Those political development forced Eni to temporarily interrupt or reduce its production activities, negatively affecting Eni's results of operations and cash flow until the situation began to stabilize. Although our production levels in Libya since 2015 have returned to the levels achieved prior to the outbreak of the civil war, the geopolitical situation remains unstable and unpredictable. In 2016, Eni's facilities in Libya produced on average 346 KBOE/d, registering a decrease of approximately 3% compared to 2015. For further information on this matter, see "Item 3 – Risk factors".

Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert area and includes six contract areas. Onshore contract areas are: (i) Area A consisting in the former concession 82 (Eni's interest 50%); (ii) Area B, former concessions 100 (Bu Attifel field) and the NC 125 Block (Eni's interest 50%); (iii) Area E with El Feel (Elephant) field (Eni's interest 33.3%); and (iv) Area F with Block 118 (Eni's interest 50%). Offshore contract areas are: (i) Area C with the Bouri oil field (Eni's interest 50%); and (ii) Area D with Blocks NC 41 and NC 169 (onshore) that feed the Western Libyan Gas Project (Eni's interest 50%).
In the exploration phase, Eni is operator in the onshore contract Areas A, B and offshore Area D.
Exploration and production activities in Libya are regulated by six Exploration and Production Sharing Agreement contracts (EPSA). The licenses of Eni's assets in Libya expire in 2042 and 2047 for oil&gas properties, respectively.

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Development activities concerned: (i) planned facilities downtime at the Mellitah treatment plant, the Sabratha production platform and treatment facilities of the Western Libyan Gas Project; (ii) positioning and installation activities as well as linkage of the new FSO unit at the Bouri production field and start-up at the beginning of 2017; (iii) a second development phase of the Bahr Essalam field (Eni's interest 50%) with the completion of 10 offshore wells of which 9 wells already drilled in 2016. The EPCI contract was awarded to supply and installation of flowlines. First gas is expected in 2018; and (iv) the linkage of one additional production wells at the Wafa field (Eni's interest 50%) and activities in order to mitigate the natural production decline in the area.

Morocco. In March 2016, Eni signed a Farm-Out Agreement (FOA) with Chariot Oil & Gas that includes the operatorship to Eni and a 40% stake enter into Rabat Deep Offshore exploration permits I-VI offshore Morocco. In October 2016, the relevant country's Authorities approved the agreement.

Tunisia. Eni has been present in Tunisia since 1961. In 2016, Eni's production amounted to 10 KBOE/d.

Eni's activities are located mainly in the Southern Desert areas and in the Mediterranean offshore facing Hammamet. Exploration and production in this country are regulated by concessions.

Production mainly comes from operated Maamoura and Baraka offshore blocks (Eni's interest 49%) and the Adam (Eni operator with a 25% interest), Oued Zar (Eni operator with a 50% interest), Djebel Grouz (Eni operator with a 50% interest), MLD (Eni's interest 50%) and El Borma (Eni's interest 50%) onshore blocks.

Production optimization represents the main activity currently performed in the above listed concessions to mitigate the natural field production decline.

Exploration activities yielded positive results with the Larich Est-1 discovery well, which put into production through a tie-in to the existing treatment facilities of the MLD concession.

Sub-Saharan Africa

Eni's operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Ghana, Mozambique and Nigeria. In 2016, Sub-Saharan Africa accounted for 19% of Eni's total worldwide production of oil and natural gas.

Angola. Eni has been present in Angola since 1980. In 2016, Eni's production averaged 112 KBOE/d. Eni's activities are concentrated in the conventional and deep offshore.

The main Eni's asset in Angola is the Block 15/06 (Eni operator with a 36.84% interest) with the West Hub project, where production started up in 2014 and the East Hub development project with production start-up achieved in February 2017. Eni participates in other producing blocks: (i) Block 0 in Cabinda (Eni's interest 9.8%) north of the Angolan coast; (ii) Development Areas in the former Block 3 (Eni's interest 12%) offshore the Congo Basin; (iii) Development Areas in the Block 14 (Eni's interest 20%) in the deep offshore west of Block 0; (iv) the Lianzi Development Area in the Block 14 K/A IMI (Eni's interest 10%), where a unitization was implemented with the Congo-Brazzaville area; and (v) Development Areas in the former Block 15 (Eni's interest 20%) in the deep offshore of the Congo Basin.

Eni retains interests in other non-producing concessions, particularly the Block 35/11 (Eni operator with a 30% interest), Block 3/05-A (Eni's interest 12%), onshore Cabinda North block (Eni's interest 15%) and the Open Areas of Block 2 assigned to the Gas Project (Eni's interest 20%).

Exploration and production activities in Angola are regulated by concessions and PSAs.

The development program of the West Hub project plans to hook up the Block's discoveries to the N'Goma FPSO in order to support production plateau. In 2016, production start-up was achieved at the M'Pungi and M'Pungi North fields, with a production ramp-up of approximately 81 KBBL/d (approximately 28 KBBL/d net to Eni) in the area. Planned activities included to be put into production 5 additional discoveries.

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In February 2017, production start-up was achieved at the East Hub project by means of the linkage of Cabaça South East field to the FPSO Armada Olombendo.
In the Block 15/06, with the completion of the East Hub project, production derived from five fields. Management plans to put into production two additions discoveries by the end of 2018.
Early production phase started up at the Mafumeira Sul project in the Block 0. Development activities progressed, with the completion expected during 2017 and a peak production of 100 KBOE/d.
Other development activities concerned: (i) the completion of the Congo River Crossing project to supply gas production of Block 0 and 14 to Angola LNG liquefaction plant (Eni’s interest 13.6%) which started up in April 2016 with a production of 6 KBOE/dnet to Eni; and (ii) development program of the Kizomba satellites Phase 2 (Eni’s interest 20%) which will be started up leveraging on the production and treatment facilities in the area.
In the medium term, management expects to increase Eni’s production to 146 KBOE/d reflecting additions from ongoing development projects.
Congo. Eni has been present in Congo since 1968. In 2016, production averaged 92 KBOE/d net to Eni.
Eni’s activities are concentrated in the conventional and deep offshore facing Pointe Noire and onshore. Eni’s main operated oil producing interests in Congo are the Zatchi (Eni’s interest 56%), Loango (Eni’s interest 42.5%), Ikalou (Eni’s interest 100%), Djambala (Eni’s interest 50%), Foukanda and Mwafi (Eni’s interest 58%), Kitina (Eni’s interest 52%), Awa Paloukou (Eni’s interest 90%), M’Boundi (Eni’s interest 83%), Kouakouala (Eni’s interest 75%), Nené Marine (Eni 65%), Zingali and Loufika (Eni’s interest 100%) fields.

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Other relevant not operated producing areas are represented by a 35% interest in the Pointe Noire Grand Fond, PEX and Likouala permits.
Exploration and production activities in Congo are regulated by Production Sharing Agreements.
In December 2016, production ramp-up was achieved at the Nené Marine field with the completion of the second development phase, sanctioned in 2015.
Development activities progressed at the Litchendjili production field and during the year peak production of approximately 16 KBOE/d was achieved. Gas production feeds the CEC power plant (Eni's interest 20%).
In the medium term, management expects to maintain production on the present level.
Ghana. Eni has been present in Ghana since 2009 and currently is the operator of the Offshore Cape Three Points (Eni's interest 44.44%) permits which is regulated by a concession agreement. The license expires in 2036.
Development activities concerned the OCTP integrated oil&gas development plan to put into production the Sankofa, Sankofa East and Gye Nyame discoveries. First oil is expected in 2017 and first gas in 2018. In 2016, the drilling activity of 18 development wells was completed and the renovation of a FPSO unit was performed. Contracts were awarded for the installation of sea-lines and the construction of onshore gas plant.
In March 2016, Eni was awarded the operatorship of the exploration license Cape Three Points Block 4 (Eni's interest 42.47%), located in the offshore of the country.
Mozambique. Eni has been present in Mozambique since 2006, following the acquisition of the Area 4

offshore Rovuma Basin block, located in the north of the country. Eni currently holds a 50% indirect interest in the block through a 71.4% stake in Eni East Africa, which is operator of the Area 4 concession with a 70% interest. The other partners in Area 4 are Galp, Kogas, ENH with a participating interest of 10% each and CNPC that holds a 20% indirect participation in Area 4 through its participation in the shareholding of Eni East Africa.
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 Coral gas discovery which falls entirely in Area 4.

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During the exploration period, which has expired in 2015, six Discovery Areas (DA) were identified in Area 4. Pursuant to the Decree Law 02/2014 multiple 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 Government of Mozambique will give right to a Development and Production Period of the duration of 30 years, further extendable pursuant to the terms of the Area 4 EPCC and the applicable Petroleum Law.

Eni also operates the exploration offshore Block A-5A (Eni's interest 34%), in the deep offshore of Zambesi.

In March 2017, ExxonMobil and Eni signed sale and purchase agreement to acquire a 25% indirect interest in the Area 4 block, offshore Mozambique. The agreed terms include a cash price of approximately $2.8 billion. The acquisition will be completed subject to satisfaction of certain conditions precedent, including clearance from Mozambican and other regulatory authorities. Following completion of the transaction, Eni East Africa will be co-owned by Eni and ExxonMobil with a 35.7% stake and the remaining interest of 28.6% by CNPC. Eni will continue to lead the Coral Floating LNG project and all upstream operations in Area 4, while ExxonMobil will lead the construction and operation of natural gas liquefaction facilities onshore. This operating model will enable the use of best practices and skills within Eni and ExxonMobil with each company focusing on distinct and clearly defined scopes while preserving the benefits of a fully integrated project.

The first plan of development was submitted to the Government of Mozambique in December 2014 in relation to the initial exploitation of the Coral gas resources. The Coral South Development Plan, which was approved by the Government in February 2016, envisages the installation of a floating unit for the treatment, liquefaction and storage of natural gas (Floating LNG - FLNG) with a capacity of over 3.3 mmtonnes/y fed by 6 subsea wells. Eni expects to produce up to 5 TCF of gas with a start-up expected in mid-2022.

In October 2016, Eni and its Area 4 partners signed a binding agreement with BP for the sale of the entire volumes of LNG produced by the Coral South Project, for a period of over twenty years. In November 2016, Eni's Board of Directors approved the investment for the first development phase of the Coral discovery. The FID on the project will turn effective once all Area 4 partners sanctioned it and the project financing, which is currently being finalized, will be underwritten.

The development plan of the Mamba project, comprises construction of two onshore LNG trains with a combined capacity of 10 mmtonnes/y and the drilling of 16 subsea wells, with start-up in 2023. Eni expects to produce up to 14 TCF of gas according to its independent industrial plan, coordinated with the operator of Area 1 (Anadarko). The FID is expected in 2018.

Nigeria. Eni has been present in Nigeria since 1962. In 2016, Eni's oil&gas production averaged 112 KBOE/d located mainly onshore and offshore the Niger Delta.

In the development/production phase Eni operates onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni's interest 20%) and offshore OML 125 (Eni's interest 85%) and OPL 245 (Eni's interest 50%), holding interests in OML 118 (Eni's interest 12.5%) and in OML 119 and 116 Service Contracts. As partners of SPDC JV, the largest joint venture in the country, Eni also holds a 5% interest in 17 onshore blocks and in 1 conventional offshore block and with a 12.86% interest in 2 conventional offshore blocks.

In the exploration phase Eni operates offshore OML 134 (Eni's interest 85%), 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 OML 135.

Exploration and production activities in Nigeria are regulated mainly by Production Sharing Agreements and concession contracts as well as service contracts, in two blocks, where Eni acts as contractor for State-owned Company.

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On January 27, 2017, Eni's subsidiary Nigerian Agip Exploration Ltd became aware of an Interim Order of Attachment ("Order") issued by the Nigerian Federal High Court, sitting in Abuja, upon request from the Economic and Financial Crime Commission (EFCC), attaching the property OPL 245, pending the Nigerian proceeding. Both Eni and Shell made a prompt application to discharge the Order. On March 17, 2017, the Nigerian Court discharged the Order. On that basis, management has concluded that no impairment of the asset was required. After the inception of the judicial proceeding in Italy, which dates back to July 2014, Eni's Board of Statutory Auditors jointly with the Eni Watch Structure has engaged a US leading law firm to perform an independent review of the issue. Based on the outcome of this review, during which the law firm appointed by Eni has also assessed material and the information made available from the judicial authorities, no wrongdoing has been detected on Eni side in the awarding process to Eni of the license.

The development activities concerned: (i) drilling activity and production start-up of three additional wells, two production and one water-injection, at the Bonga field in the OML 118 block; (ii) the drilling campaign within the integrated project in the Gbaran-Ubie area in the OML 28 block (Eni's interest 5%), aimed to supply natural gas to the Bonny liquefaction plant. Start-up was achieved in the second half of 2016; and (iii) the OML 43 block (Eni's interest 5%), where the development plan of the Forcados-Yokri field provides hook-up the last 12 of 23 production wells already drilled, the upgrading of existing flowstations and the construction of transport facilities. Start-up is expected in the first half of 2017.

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 is operational, with a treatment capacity of approximately 1,236 BCF/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on six trains. Natural gas supplies to the plant are currently provided under gas supply agreements with an expiring date in fifteen years from the SPDC JV and the NAOC JV (operating the OMLs 60, 61, 62 and 63 blocks) with an average amount of approximately 2,825 mmCF/d for the next four years (approximately 265 mmCF/d net to Eni corresponding to approximately 49 KBOE/d). 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 Co.

In January 2017, Eni signed with the Nigerian National Petroleum Corporation (NNPC) a Memorandum of Understanding, which strengthen cooperation in the energy sector.

Kazakhstan

Eni has been present in Kazakhstan since 1992. Eni is co-operator of the Karachaganak field and partner in the North Caspian Sea Production Sharing Agreement (NCSPSA). In 2016, Eni’s operations in Kazakhstan accounted for 6% of its 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

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the Kashagan field, which was discovered in the Northern section of the contractual area in the year 2000 over an undeveloped 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 currently of 16.81%, CNPC with 8.33%, and Inpex with 7.56%.

On September 28, 2016, production re-started at the Kashagan field with the completion of works to fully replace the damaged pipelines following the gas leak occurred at the end of 2013. The production of 180 KBOE/d was achieved by year-end (31 KBOE/d net to Eni). The production capacity of 370 KBBL/d planned for the Phase 1 is expected to be achieved during 2017, when gas reinjection comes online.

The Phase 1 includes a further increase available production capacity up to 450 KBBL/d by installing additional gas compression capacity for reinjection in the reservoir. The partners submitted the scheme of this additional phase to the relevant Kazakh Authorities.

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. In addition to the expenditures for developing the field, further capital expenditures will be required to build the infrastructures needed for exporting the production to international markets.

As of December 31, 2016, Eni’s proved reserves booked for the Kashagan field amounted to 608 mmBOE, barely unchanged from 2015.

As of December 31, 2015, Eni’s proved reserves booked for the Kashagan field amounted to 611 mmBOE, recording an increase of 31 mmBBL compared to 2014 mainly due to lower marker Brent price.

As of December 31, 2014, Eni’s proved reserves booked for the Kashagan field amounted to 580 mmBOE, barely unchanged compared to 2013.

As of December 31, 2016, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.7 billion (€9.2 billion at the EUR/USD exchange rate of December 31, 2016). This capitalized amount included: (i) $7.2 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.5 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the Consortium from exiting partners upon exercise of pre-emption rights in previous years.

As of December 31, 2015, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $9.2 billion (€8.4 billion at the EUR/USD exchange rate of December 31, 2015). This capitalized amount included: (i) $6.8 billion relating to expenditure incurred by Eni for the development of the oil field; and (ii) $2.4 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the Consortium from exiting partners upon exercise of pre-emption rights in previous years.

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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 2016, production of the Karachaganak field averaged 231 KBBL/d of liquids (61 KBBL/d net to Eni) and 867 mmCF/d of natural gas (230 mmCF/d net to Eni). This field is developed by producing liquids from the deeper layers of the reservoir. The gas is marketed (about 51%) 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 91% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity of approximately 250 KBBL/d 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 (approximately 16 KBBL/d) are marketed at the Russian terminal in Orenburg.

The Expansion Project is currently under study. The project targets to install, in stages, the gas treatment plants and re-injection facilities to support liquids' production profile. The development plan is currently in the phase of technical and marketing definition of its first development phase, aimed to increase the capacity of gas re-injection.

As of December 31, 2016, Eni's proved reserves booked for the Karachaganak field amounted to 613 mmBOE, reporting an increase of 26 mmBOE from 2015 mainly due to lower marker Brent price.

As of December 31, 2015, Eni's proved reserves booked for the Karachaganak field amounted to 587 mmBOE, reporting an increase of 98 mmBOE from 2014 mainly due to lower marker Brent price.

As of December 31, 2014, Eni's proved reserves booked for the Karachaganak field amounted to 489 mmBOE, barely unchanged compared to 2013.

Rest of Asia

In 2016, Eni's operations in the Rest of Asia accounted for 7% of its total worldwide production of oil and natural gas.
China. Eni has been present in China since 1984 with activities located in the South China Sea. In 2016, Eni's production amounted to 2 KBOE/d.
Exploration and production activities in China are regulated by Production Sharing Agreements.
In 2016, hydrocarbons were produced from the offshore Blocks 16/19 through 3 platforms connected to an FPSO.

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Indonesia. Eni has been present in Indonesia since 2001. In 2016, Eni's production mainly composed of gas, amounted to 14 KBOE/d. Activities are concentrated in the Eastern offshore and onshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 14 blocks.

Exploration and production activities in Indonesia are regulated by PSAs.

In 2016 production start-up was achieved at the Bangka project (Eni's interest 20%) in the East Kalimantan.

The ongoing development activities that will ensure gas supplies to the Bontang liquefaction plant include the Jangkrik project (Eni operator with a 55% interest) in the Kalimantan offshore. This project is in the final execution phase with all the deep-offshore development subsea wells already drilled and the Floating Production Unit for gas and condensate treatment in the final stage of construction, as well as the construction of transportation and receiving facilities onshore. Production start-up is planned in 2017.

Exploration activities yielded positive results with appraisal activities at the Merakes gas discovery in the deep offshore of the East Sepinggan block (Eni operator with an 85% interest), nearby the Jangkrik project.

Iraq. Eni has been present in Iraq since 2009. Eni, leading a consortium of partners including international companies and the national oil company Missan Oil, holds a 41.6% interests in the Zubair oil field.

Development and production activities at the Zubair field 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 Production Sharing contracts.

In 2016, production of the Zubair field averaged 64 KBBL/d net to Eni.

At the beginning of March 2016, three new generation plants for the oil, gas and water treatment (Initial Production Facilities - IPF) started. Those plants together with 5 existing restructured and modernized plants increased oil and natural gas treatment capacity of Zubair field to approximately 650 KBBL/d and will ensure the maximization of the associated gas utilization.

In addition, these new facilities have also a water re-injection capacity of approximately 300 KBBL/d that will boost the Zubair's hydrocarbons production and will achieve production plateau.

The first stage of development activities (Rehabilitation Plan) of the Zubair field were completed with start-up of these new facilities.

Ongoing development activities concerned an additional development phase (Enhanced Redevelopment Plan) of the Zubair field, to achieve a production plateau of 700 KBBL/d and will ensure the application of associated gas to power generation.

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). The contracts foresee, for the onshore blocks, an exploration period of six years subdivided into three phases and for the offshore blocks a study period of two years, followed by an exploration period of six years, subdivided in 3 phases.

Pakistan. Eni has been present in Pakistan since 2000. In 2016, Eni's production mainly composed of gas amounted to 30 KBOE/d.

Exploration and production activities in Pakistan are regulated by concessions (onshore) and PSAs (offshore).

Eni's main permits in the country are Bhit/Bhadra (Eni operator with a 40% interest), Latif (Eni's interest 33.33%) and Zamzama (Eni's interest 17.75%), which in 2016 accounted for 79% of Eni's production in Pakistan.

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Production optimization through drilling activities of new development wells represents the main activity currently performed in the above listed fields to mitigate the natural field production decline.

Russia. Eni has been present in Russia through three joint ventures with Rosneft for the development of Fedynsky and Central Barents licenses (Eni's interest 33.33%) located in the Russian Barents Sea and Western Chernomorsky license (Eni's interest 33.33%) in the Black Sea since 2013.

Following the adoption of EU sanctions measures relating to the upstream sector in Russia, Eni started the required authorization before competent Authorities of the Member States of the European Union who granted the Company and the joint ventures between Eni and Rosneft certain authorization for the execution and financing of the exploration activities in Russia, under the terms of contracts entered into force before the enactment of the relevant sanctions. The current sanctions have delayed and will continue to affect the timing of implementation of the projects. For further information on this matter, see "Item 3 – Risk factors".

Turkmenistan. Eni started its activities in Turkmenistan with the purchase of the British company Burren Energy plc in 2008. Activities are focused on the onshore Nebit Dag Area in the Western part of the country. The license expires in 2032.

In 2016, Eni's production averaged 9 KBOE/d.

Exploration and production activities in Turkmenistan are regulated by PSAs.

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.

Production optimization represents the main activity currently performed in the area to mitigate the natural field production decline.

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 2016, Eni's operations in Americas area accounted for 10% 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. In 2016, Eni's production averaged 11 KBBL/d.

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.

In December 2016, development activities of the Villano Phase VI project started up with the drilling of the first of two infilling wells.

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Mexico. Eni has been present in Mexico since 2015. Eni is operator of the Block 1 (Eni's interest 100%) to develop the Amoca, Miztón and Tecoalli fields, located in the Gulf of Mexico shallow waters. The delineation campaign of the fields was submitted to the Mexican Authorities in the first quarter of 2016 and plans the drilling of four wells in order to define a fast track and synergic development plan.

In January 2017, the delineation campaign started with the first well.

Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2016, Eni's production averaged 70 mmCF/d. Eni owns a 17.3% interest in the North Coast Marine Area 1 Block, located offshore North of Trinidad. Exploration and production activities in Trinidad and Tobago are regulated by PSAs.

Production is provided by the Chaconia, Ixora, Hibiscus, Ponsettia, Bougainvillea and Heliconia gas fields. Production is supported by two fixed platforms linked to the Hibiscus processing facility. Natural gas is used to feed trains 2, 3 and 4 of the Atlantic LNG liquefaction plant on Trinidad's coast and it is sold under long-term contracts with prices linked to the United States, as well as alternative destinations markets.

United States. Eni has been present in the United States since 1968. Activities are performed in the shallow and deep offshore of the Gulf of Mexico, onshore and offshore in Alaska, and in Texas onshore.
In 2016, Eni's oil&gas production was 91 KBOE/d mainly from the Gulf of Mexico and Alaska fields.
Exploration and production activities in the United States are regulated by concessions.
Eni holds interests in 84 exploration and production blocks in the Gulf of Mexico, of which 44 are operated by Eni. The main operated fields are Allegheny and Appaloosa (Eni's interest 100%), Pegasus (Eni's interest 85%), Longhorn, Devils Towers and Triton (Eni's interest 75%). Eni also holds interests in Europa (Eni's interest 32%), Hadrian South (Eni's interest 30%), Medusa (Eni's interest 25%), Lucius (Eni's interest 8.5%), K2 (Eni's interest 13.4%), Frontrunner (Eni's interest 37.5%) and Heidelberg (Eni's interest 12.5%) fields.

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During the year, production start-ups were achieved in the Gulf of Mexico at: (i) the Heidelberg field (Eni's interest 12.5%) in the deep-water Gulf of Mexico, with a production of approximately 3 KBOE/d net to Eni. During 2017 planned development activities will be completed; (ii) the Phase 2 development of Lucius field (Eni's interest 8.5%) with production ramp-up to 100 KBOE/d (8 KBOE/d net to Eni); and (iii) the Devil's Tower South-West production well within the development program of the operated Devil's Tower field, with a production of approximately 2 KBOE/d.

To achieve the highest safety standards of operations, Eni became a member of the HWCG Consortium of Gulf of Mexico operators. The HWGC 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".

Eni holds interests in 43 exploration and development blocks in Alaska, with interests ranging from 30 to 100%; Eni is the operator in 27 of these blocks.

Eni's production is provided by Nikaitchuq (Eni operator with a 100% interest) and Oooguruk (Eni's interest 30%) fields with a 2016 overall net production of approximately 24 KBBL/d.

In Texas onshore, Eni's production comes from the Alliance Area (Eni's interest 27.5%).

Venezuela. Eni has been present in Venezuela since 1998. In 2016, Eni's production averaged 60 KBOE/d.

Activity is concentrated both offshore (Gulf of Venezuela and Gulf of Paria) and onshore in the Orinoco Oil Belt.

Exploration and production of the oil Junin 5 and Corocoro fields are regulated by the terms of the so-called Empresa Mixta. Under the new legal framework, only a company incorporated under the law of Venezuela is entitled to conduct petroleum operations. A stake of at least 60% in the capital of such company is held by an affiliate of the Venezuela state oil company, PDVSA, preferably Corporación Venezuelana de Petróleo (CVP). The Perla gas field is operated by Cardon IV, a joint venture 50%-50% Eni and Repsol.

Eni's production comes from the giant 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.

Development activities performed in 2016 were: (i) ongoing drilling activities at the Junin 5 oil field. The production level at year-end was approximately 18 KBBL/d at 100%. Possible optimization of development program is currently under evaluation; and (ii) the completion of the first development phase at the Perla field. The six wells currently on stream are producing approximately 540 mmCF/d at 100%. The gas will be mainly used by PDVSA for the domestic market, under the Gas Sales Agreement in place until 2036. The Perla project includes two additional development phases to achieve a production plateau of approximately 1,200 mmCF/d.

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 2016, 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. In 2016, Eni's production of oil and natural gas averaged 23 KBOE/d. Activities are focused on conventional and deep offshore fields.

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Exploration and production activities in Australia are regulated by concession agreements, whereas in the cooperation zone between Timor Leste and Australia (Joint Petroleum Development Area - JPDA) they are regulated by PSAs. 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 NT/RL7 (Eni’s interest 32.5%). In addition Eni holds interest in 6 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.

As of December 31, 2016, Eni outstanding trade receivables amounted to $278 million towards the National Iranian National Oil Co (NIOC) which were recorded in connection with the settlement agreement recognized in 2015. This amount was curtailed from the amount outstanding at December 31, 2015 ($339 million). The State counterparties expressed their willingness to negotiate a repayment plan of overdue receivables based on arrangements relating the sale of volumes of the Iranian counterpart equity crude and the attribution to Eni of a percentage of the sale proceeds. This agreement has been enacted in the last months of 2016 with a reimbursement to Eni of $44 million. Negotiations are underway to identify additional crude volumes to be marketed, some of which have already been awarded to Eni in early 2017, with the aim of fully recovering the overdue amounts. Eni had no payables towards NIOC as of December 31, 2016. Eni made payments in the region of $1 million to the Iranian Social Security Organization in connection to health and social security insurance for which Eni retains at the balance sheet date a residual payable amounting to $10 million date, which will be settled upon termination of our presence in the country.

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 2016, Eni’s worldwide sales of natural gas amounted to 88.93 BCM, including 2.62 BCM of gas sales made directly by Eni’s Exploration & Production segment. Sales in Italy amounted to 38.43 BCM, while sales in European markets were 42.43 BCM that included 4.37 BCM of gas sold to certain importers to Italy.

In the Gas & Power segment we expect a continuing weak outlook for natural gas sales and prices due to structural headwinds in the industry as we forecast oversupplies and strong competition across all of our main markets in Europe, including Italy.

Supply of natural gas

In 2016, Eni’s consolidated subsidiaries supplied 82.64 BCM of natural gas, down by 2.75 BCM, or 3.2% from 2015. Gas volumes supplied outside Italy (76.64 BCM from consolidated companies), imported

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in Italy or sold outside Italy, represented approximately 93% of total supplies, down by 2.02 BCM, or 2.6% compared to the previous year, due to lower volumes purchased in Libia (down 2.38 BCM), Russia (down 2.34 BCM) and in the Netherlands (down 2.13 BCM), partly offset by higher volumes purchased in Algeria (up 6.85 BCM).

Supplies in Italy (6.00 BCM) decreased from 2015 (down 0.73 BCM or 10.8%) due to the production shutdown in the Val d'Agri district during the period April-August 2016. In 2016, main gas volumes from equity production derived from: (i) Italian gas fields (4.5 BCM); (ii) certain Eni fields located in the British and Norwegian sections of the North Sea (2.2 BCM); (iii) Libyan fields (1.5 BCM); (iv) the United States (1.4 BCM); and (v) other European areas (0.2 BCM).

Considering also direct sales of the Exploration & Production segment and LNG supplied from the Bonny liquefaction plant in Nigeria, supplied gas volumes from equity production were approximately 15.02 BCM representing 17% 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	2014	2015	2016
	(BCM)		
Italy	6.92	6.73	6.00
Outside Italy	75.99	78.66	76.64
Russia	26.68	30.33	27.99
Algeria (including LNG)	7.51	6.05	12.90
Libya	6.66	7.25	4.87
the Netherlands	13.46	11.73	9.60
Norway	8.43	8.40	8.18
the United Kingdom	2.64	2.35	2.08
Hungary	0.38	0.21	0.02
Qatar (LNG)	2.98	3.11	3.28
Other supplies of natural gas	5.56	7.21	5.81
Other supplies of LNG	1.69	2.02	1.91
Total supplies of subsidiaries	82.91	85.39	82.64
Withdrawals from (input to) storage	(0.20)		1.40
Network losses, measurement differences and other changes	(0.25)	(0.34)	(0.21)
Volumes available for sale of Eni's subsidiaries	82.46	85.05	83.83
Volumes available for sale of Eni's affiliates	3.65	2.67	2.48
E&P volumes	3.06	3.16	2.62
Total volumes available for sale	89.17	90.88	88.93

Sales of natural gas

In 2016, natural gas sales amounted to 88.93 BCM (including Eni's own consumption, Eni's share of sales made by equity-accounted entities and upstream sales in Europe and in the Gulf of Mexico), representing a decrease of 1.95 BCM, or 2.1% from the previous year. Sales in Italy were barely unchanged (38.43 BCM); lower volumes in the wholesale and residential segment were partly offset by higher spot volumes. Sales in the European markets were 38.06 BCM, down by 0.6% from 2015.

Direct sales of Exploration & Production segment in Europe and the Gulf of Mexico (2.62 BCM) decreased by 0.54 BCM due to lower volumes marketed in the United Kingdom and the United States, partially offset by higher sales in Norway.

Sales to long-term buyers were down by 5.2% compared to the previous year, due to shorter availability of Libyan output as well as lower sales to Extra European markets (down by 14.7%) driven by lower LNG volumes marketed in the Far East, due to the lack of contracts renewal.

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

Natural gas sales by entities	2014	2015	2016
	(BCM)		
Total sales of subsidiaries	81.73	84.94	83.34
Italy (including own consumption)	34.04	38.44	38.43
Rest of Europe	43.07	41.14	40.52
Outside Europe	4.62	5.36	4.39
Total sales of Eni's affiliates (Eni's share)	4.38	2.78	2.97
Italy			
Rest of Europe	3.15	1.75	1.91
Outside Europe	1.23	1.03	1.06
Total sales of G&P	86.11	87.72	86.31
E&P in Europe and in the Gulf of Mexico(a)	3.06	3.16	2.62
Worldwide gas sales	89.17	90.88	88.93

(a)
E&P sales include volumes marketed by the Exploration & Production segment in Europe (2.60, 2.75 and 2.32 BCM in 2014, 2015 and 2016, respectively) and in the Gulf of Mexico (0.46, 0.41 BCM and 0.30 in 2014, 2015 and 2016, respectively).

Natural gas sales by market	2014	2015	2016
	(BCM)		
ITALY	34.04	38.44	38.43
Wholesalers	4.05	4.19	3.83
Italian gas exchange and spot markets	11.96	16.35	17.08
Industries	4.93	4.66	4.54
Medium-sized enterprises and services	1.60	1.58	1.72
Power generation	1.42	0.88	0.77
Residential	4.46	4.90	4.39
Own consumption	5.62	5.88	6.10
INTERNATIONAL SALES	55.13	52.44	50.50
Rest of Europe	46.22	42.89	42.43
Importers in Italy	4.01	4.61	4.37
European markets	42.21	38.28	38.06
Iberian Peninsula	5.31	5.40	5.28
Germany/Austria	7.44	5.82	7.81
Benelux	10.36	7.94	7.03
Hungary	1.55	1.58	0.93
United Kingdom/Northern Europe	2.94	1.96	2.01

Turkey	7.12	7.76	6.55
France	7.05	7.11	7.42
Other	0.44	0.71	1.03
Extra European markets	5.85	6.39	5.45
E&P in Europe and in the Gulf of Mexico	3.06	3.16	2.62
WORLDWIDE GAS SALES	89.17	90.88	88.93

European markets
A review of Eni's presence in the key European markets is presented below.

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Benelux. Eni holds a leadership position in the Benelux countries (Belgium, the Netherlands and Luxembourg) granted by a direct presence, through the Belgium Gas & Power branch, and its significant exposure to spot markets in Western Europe. Furthermore Eni operates in the retail and middle market through its subsidiary. In 2016, sales in Benelux amounted to 7.03 BCM (7.94 BCM in 2015), down by 0.91 BCM, or 11.5%.

France. Eni sells natural gas to industrial clients and wholesalers, as well as to the segments of retail and middle market. Eni is present in the French market through its direct commercial activities and through its subsidiary. In 2016, sales in France amounted to 7.42 BCM (7.11 BCM in 2015), an increase of 0.31 BCM, or 4.4%, from a year ago.

Germany-Austria. Eni operates in Germany-Austria through its direct commercial activities and through its subsidiaries. In 2016, total sales in Germany-Austria amounted to 7.81 BCM, an increase of 1.99 BCM, or 34.2%.

The LNG business

Eni LNG business can count currently on a portfolio of contracted long-term supplies mainly from 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. In 2017, the G&P LNG business will start marketing volumes of gas produced at the E&P large Jangkrik gas complex, off Indonesia. Final markets of that gas include the Chinese market and other areas. The business's profitability will be also driven by enhancing the commercial presence in premium markets and continuing integration with trading activities.

LNG sales	2014	2015	2016
	(BCM)		
G&P sales	8.9	9.0	8.1
Rest of Europe	5.0	4.8	5.2
Extra European markets	3.9	4.2	2.9
E&P sales	4.4	4.5	4.3
Liquefaction plants:			
- Soyo (Angola)	0.1		0.1
- Bontang (Indonesia)	0.5	0.5	0.4
- Point Fortin (Trinidad & Tobago)	0.6	0.7	0.7
- Bonny (Nigeria)	2.8	2.8	2.6
- Darwin (Australia)	0.4	0.5	0.5
	13.3	13.5	12.4

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 middle to large industrial users, the Company has been developing a commercial offer that provides the combined supply of gas, power and fuels.

In 2016, power sales (37.05 TWh) were directed to the free market (74%), the Italian Power Exchange (15%), industrial sites (9%) and others (2%). Compared to 2015, electricity sales were up by 6.2%, due to higher volumes sold to wholesalers and middle market, partially offset by lower volumes traded to small and medium size enterprises and large clients.

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Power availability	2014	2015	2016
	(TWh)		
Power generation sold	19.55	20.69	21.78
Trading of electricity (a)	14.03	14.19	15.27
	33.58	34.88	37.05
Power sales by market			
Free market (a)	24.86	25.90	27.49
Italian Exchange for electricity	4.71	5.09	5.64
Industrial plants	3.17	3.23	3.11
Other (a)	0.84	0.66	0.81
	33.58	34.88	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 2016, power generation was 21.78 TWh, up by 1.09 TWh, or 5.3% from 2015, mainly due to higher production at Brindisi, Ferrara, Ferrera Erbognone and Ravenna plants following increasing demand. As of December 31, 2016, installed operational capacity was 4.7 GW (4.9 GW as of December 31, 2015). Electricity trading reported an increase to 15.27 TWh, due to higher purchases on the spot market (up 7.6%) reflecting the optimization of inflows and outflows of power.

Site	Total installed capacity in 2016 (GW)	Technology	Fuel
Brindisi	1.3	CCGT	gas
Ferrera Erbognone	1.0	CCGT	gas/syngas
Livorno (a)	-	Power station	gas/fuel oil
Mantova	0.8	CCGT	gas
Ravenna	1.0	CCGT	gas
Ferrara (b)	0.4	CCGT	gas
Bolgiano	0.1	Power station	gas
	4.7		

(a)
Since March 1, 2016 Livorno was tranferred to R&M segment.

(b)
Eni’s share of capacity.

Power generation		2014	2015	2016
Purchases				
Natural gas	(mmCM)	4,074	4,270	4,334
Other fuels	(ktoe)	338	313	360
- of which steam cracking		104	87	105
Production				
Electricity	(TWh)	19.55	20.69	21.78
Steam	(ktonnes)	9,010	9,318	7,974
Installed generation capacity	(GW)	4.9	4.9	4.7

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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 (Russia, Algeria, Libya and the North Sea). Eni pays 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 to 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-kilometer 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-kilometer 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-kilometer 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, as well as in the marketing of refined products primarily in Europe. In Italy, Eni is the largest refining and marketing operator in terms of capacity and market share. Company operations are fully integrated through refining, supply, logistics and marketing in order to maximize cost efficiencies and operational effectiveness.

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In 2016 refining margins in the Mediterranean area decreased by approximately 50% y-o-y due to a high level of inventories of gasoline and gasoil because of a high utilization rate of refineries as well as availability of products coming from the Middle East. Looking forward, management believes that refining margins in the medium term will remain stable on the 2016 level; in the longer term, margins will improve as a result of the 2020 IMO legislation, which will lead to the substitution of bunker fuel oil with cleaner fuels (gasoil and LNG). In marketing, competition remains tough, in particular from unbranded and large retailers.

Supply

In 2016, a total of 23.35 mmtonnes of crude were purchased (compared with 24.80 mmtonnes in 2015), of which 3.43 mmtonnes by equity crude oil. The breakdown by geographic area was the following: approximately 43% of purchased crude came from Russian Commonwealth, 30% from the Middle East, 12% from Italy, 11% from North Africa, 1% from West Africa, 1% from North Sea and 2% from other areas.

Refining

In 2016, Eni refinery capacity (balanced with conversion capacity) was approximately 27.4 mmtonnes (equal to 548 KBBL/d), with a conversion index of 50%. 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 49% conversion index. In 2016, Eni's refineries throughputs in Italy and outside Italy were 24.52 mmtonnes.

Refining system in 2016

	Ownership (%)	Balanced refining capacity (Eni's share) (KBBL/d)	Utilization rate (Eni's share) (KBBL/d)	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	49	34	16	90	29
Italy								
Sannazzaro	100	200	98	71	34	16	51	29
Taranto	100	104	73	38		0	39	0
Livorno	100	84	91	11				
Partially owned refineries		160	93	52	143	25	75	27
Italy								
Milazzo	50	100	90	60	45	25	32	
Germany								
Vohburg/Neustadt (Bayernoil)	20	41	96	36	49			
Schwedt	8.33	19	100	42	49		43	27
Total		548	90	50	177	41	165	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 71%. Located in the Po Valley, in the center of the Northern Italy, Sannazzaro is one of the most efficient

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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%.
The Taranto refinery has a balanced capacity of 104 KBBL/d and a conversion index of 38%. 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 dearomatization unit (DEA) – for the production of fuels; a propane de-asphalting (PDA), aromatics extraction and dewaxing 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 (2016) (ktonnes/y)	Capacity (at regime) (ktonnes/y)	Throughput (2016) (ktonnes/y)
Wholly-owned				
Venezia	100	360	560	212
Gela	100		750	
Total green refineries		360	1,310	212

Green Refining
Eni fully owns the green refinery of Venice and the site of Gela, where another green refinery will be realized.
The Venice green refinery entered into production in June 2014, with a production capacity of 360 ktonnes/y. The refinery exploits the proprietary EcofiningTM technology to transform vegetable oil in hydrogenated bio-fuels. A second phase of development is underway. At regime, the production will satisfy approximately half of Eni bio-fuels needs required for being compliant with the EU environmental normative aimed at reducing the CO_2 emission.
The Gela refinery is located on 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

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into a bio-refinery with the Ministry for Economic Development and Local Authorities. In 2016 Eni's activities continued in line with the commitments foreseen in the Memorandum of Understanding. In April 2016 Eni began the construction activities at the Green Refinery project. The refinery will have a capacity of 750 ktonnes/y. The conversion will leverage on the application of ecofining proprietary technology, developed and patented by Eni, to convert unconventional and second generation raw materials into green diesel, a highly sustainable biofuel.

Gela reconversion represents the first integrated and cross businesses' project which Eni is developing in Italy to combine the needs of the business and those of the communities living in the area.

The agreement foresees also:

- the launch of new hydrocarbon exploration and production activities in the Region of Sicily and the offshore area;
- the realization of a modern hub for shipping locally produced crude oil and green fuel produced on the site;
- a feasibility study, to identify LNG and CNG storage and transport infrastructure in Gela, as well as the realization of a project for the production of natural latex from natural products with the relative development of the agricultural supply chain;
- the set-up of a competence center focused on safety issues;
- a plan for the environmental remediation of plants and areas that will gradually lose their industrial destination.

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

Availability of refined products	2014	2015	2016
	(mmtonnes)		
ITALY			
Refinery throughputs			
At wholly-owned refineries	16.24	18.37	17.37
Less input on account of third parties	(0.58)	(0.38)	(0.27)
At affiliated refineries	4.26	4.73	4.51
Refinery throughputs on own account	19.92	22.72	21.61
Consumption and losses	(1.33)	(1.52)	(1.53)
Products available for sale	18.59	21.20	20.08
Purchases of refined products and change in inventories	7.19	6.22	6.28
Products transferred to operations outside Italy	(0.72)	(0.48)	(0.39)
Consumption for power generation	(0.57)	(0.41)	(0.37)
Sales of products	24.49	26.53	25.60
OUTSIDE ITALY			
Refinery throughputs on own account	5.11	3.69	2.91
Consumption and losses	(0.21)	(0.23)	(0.22)
Products available for sale	4.90	3.46	2.69

Purchases of finished products and change in inventories	4.48	4.77	4.72
Products transferred from Italian operations	0.72	0.48	0.40
Sales of products	10.10	8.71	7.81
Refinery throughputs on own account	25.03	26.41	24.52
of which: refinery throughputs of equity crude on own account	5.81	5.04	3.43
Total sales of refined products	34.59	35.24	33.41
Crude oil sales	0.33	0.27	0.20
TOTAL SALES	34.92	35.51	33.61

In 2016, refining throughputs were 24.52 mmtonnes, down by 7.2 % from 2015 due to lower availability of domestic crude oil driven by the shutdown of the Val d'Agri field at the Taranto plant during the period of April - August 2016, as well as other planned maintenance turnarounds (Livorno and Milazzo), partially offset by higher volumes processed at Sannazzaro despite the incident occurred in December 2016. On a homogeneous basis, when excluding the impact of the disposal of CRC refinery in Czech Republic finalized on April 30, 2015, refining throughputs reported a decrease of 4.5% compared to the 2015.

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Outside Italy, Eni's refining throughputs were 2.91 mmtonnes, down by 0.78 mmtonnes or 21.1% from previous year, mainly due to the above-mentioned divestment in the Czech Republic finalized in the second quarter of 2015.
Total throughputs in wholly-owned refineries were 17.37 mmtonnes, down by 1 mmtonne, or 5.4% compared with 2015, determining a refinery utilization rate (ratio between throughputs and balanced capacity) of 89.5%.
Approximately 14.8% of processed crude was equity, down by approximately 6 percentage points from 2015 (20.4%).

Logistics

Eni is a leading operator in the Italian oil and refined products storage and transportation business.
It owns an integrated infrastructure consisting of 17 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, Petrolig, Petroven, Petra, Seram, Disma, Toscopetrol). Since the beginning of 2017 Petrolig joint venture ends. 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 1,462 kilometers.
Secondary distribution to retail and wholesale markets is outsourced to independent tanker carriers.

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	2014	2015	2016
	(mmtonnes)		
Italy			
Retail	6.14	5.96	5.93
Wholesale	7.57	7.84	8.16
	13.71	13.8	14.09
Petrochemicals	0.89	1.17	1.02
Other sales	9.89	11.56	10.49
Total	24.49	26.53	25.6
Outside Italy			
Retail	3.07	2.93	2.66
Wholesale	5.03	4.25	3.61
	8.10	7.18	6.27
Other sales	2.00	1.53	1.54
Total	10.1	8.71	7.81
TOTAL SALES	34.59	35.24	33.41

In 2016, sales volumes of refined products (33.41 mmtonnes) were down by 1.83 mmtonnes or by 5.2% from 2015, mainly due to the assets disposal in the Czech Republic and Slovakia finalized in July 2015 as well as in Slovenia and Hungary in the second half of 2016.

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Retail sales in Italy

In 2016, retail sales in Italy were 5.93 mmtonnes, with a decrease compared to 2015 (about 30 ktonnes from 2015 or 0.5%) due to a reduction of sales in Eni highway segment, partially offset by an increase in owned stations. Average gasoline and gasoil throughput (1.551 kliters) decreased by approximately 20 kliters from 2015. Eni's retail market share in 2016 was 24.3%, down by 0.2 percentage points from 2015 (24.5%).

As of December 31, 2016, Eni's retail network in Italy consisted of 4,396 service stations, lower by 24 units from December 31, 2015 (4,420 service stations), resulting from the release of low throughput stations (27 units), offset by positive balance of acquisitions/releases of lease concessions (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 2016, retail sales of refined products in the rest of Europe (2.66 mmtonnes), recorded a reduction from 2015 (down by 9.2%). This result reflected mainly the assets disposal in the Czech Republic and Slovakia finalized in July 2015 as well as in Slovenia and Hungary in the second half of 2016. These negatives were partially offset by higher volumes traded in France, Austria and Germany. On a homogeneous basis, when excluding the impact of the assets disposal in Eastern Europe, sales increased by 1%.

At December 31, 2016, Eni's retail network in the Rest of Europe consisted of 1,226 units, decreasing by 200 units from December 31, 2015, due to the service stations disposal above mentioned. Average throughput (2,340 kliters) increased by 68 kliters compared to 2015 (2,272 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 is supported by a widespread commercial and logistical organization presence throughout Italy and articulated in local marketing offices and a network of agents and concessionaires.

In 2016, sales volumes on wholesale markets in Italy (8.16 mmtonnes) increased by 0.32 mmtonnes or 4.1% from the previous year, mainly due to higher volumes marketed of jet fuel, gasoil and fuel oil partly offset by lower sales of bunkering.

Wholesale sales in the Rest of Europe were 3.18 mmtonnes, down by 17% from 2015 due to the above-mentioned asset disposals. On a homogeneous basis, sales are barely unchanged from 2015. Supplies of feedstock to the petrochemical industry (1.02 mmtonnes) decreased by 12.8%. Other sales in Italy and outside Italy (12.03 mmtonnes) decreased by approximately 1.05 mmtonnes or 8%, mainly due to lower sales volumes to oil companies.

LPG

The marketing of LPG in Italy is supported by the refining production and a logistic network made 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 2016, Eni share of LPG market in Italy was 17.5%.

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Outside Italy, the main market of Eni is Ecuador, with a market share of 38%.

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 2016, Eni's share of lubricants market in Italy was 21%, in Europe 3% and on a worldwide base 0,6%. 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 1 mmtonnes/y of oxygenates, mainly ethers (approximately 3% of world demand, used as a gasoline octane booster) and methanol (mainly for petrochemical use). About 80% 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 20% is purchased.

Chemicals

Eni operates in the businesses of olefins and aromatics, basic and intermediate products, polystyrene, elastomers and polyethylene. Its major production sites are located in Italy and Western Europe. These are predominantly oil-based businesses with a history of losses and poor growth prospects. In fact, we face structural headwinds in our legacy basic petrochemicals and plastics businesses due to the commoditized nature of our products, low entry barriers, lack of scale, exposure to the volatility in the costs of oil-based feedstock, cyclicality in demand, and strong competitive pressures from operators with lower cost structure especially from the Middle and Far East and other weaknesses. Eni's profitability in the petrochemical businesses is particularly sensitive to movements in product margins that are mainly affected by changes in oil-based feedstock costs and the speed at which product prices adjust to higher oil prices. See "Item 3 – Risk factors".

In 2016 sales of chemical products amounted to 3,759 ktonnes, decreased from 2015 (down by 42 ktonnes, or 1.1%) mainly due to the stagnation of demand in Europe. The declines were registered in polyethylene (down by 9.8%) and styrene (down by 9.1%) following the shutdown of Ragusa and Mantova, partly offset by higher volumes in derivatives among intermediates (up by 14.8%) and elastomers (up by 6.7%), driven by demand increase in the Tyre sector.

Petrochemical production of 5,646 ktonnes decreased by 54 ktonnes (down by 0.9%). Higher decreases occurred in polyethylene (down by 8.6%) due to a weak demand and in styrene (down by 7.2%) due to planned and unplanned Mantova standstills. Derivatives productions increased (up by 10.2%) as well as elastomers (up by 7.1%) due to the recovery in sales volumes from the lower levels registered in 2015. The main decreases in production were registered at the Ragusa site (down by 45%), due to a malfunctioning occurred at the plant, as well as Ravenna and Dunkerque (olefins), Ferrara (elastomers) and Mantova sites (styrene) due to planned shutdowns of the plants. The productions of Brindisi plant increased (up by 15.7%) as well as Grangemouth site (up by 20.7%), for the start-up of the new butadiene-based rubber production line. Nominal capacity of plants barely unchanged from the previous year, with an average plant utilization rate calculated on nominal capacity of 71.4% reporting a slight decrease from 2015 (72.7%).

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

	Year ended December 31,		
	2014	2015	2016
	(ktonnes)		
Intermediates	2,972	3,334	3,417
Polymers	2,311	2,366	2,229
Total production	5,283	5,700	5,646
Consumption and losses	(2,292)	(1,908)	(2,410)
Purchases and change in inventories	472	9	523
	3,463	3,801	3,759

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

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Intermediates	2,310	1,899	1,688
Polymers	2,800	2,690	2,380
Other revenues	174	127	128
Total revenues	5,284	4,716	4,196

Intermediates

Intermediates revenues (€1,688 million) decreased by €211 million from 2015 (down by 11.1%) reflecting the lower commodity prices scenario that influences average intermediates prices. Sales increased by 4.6%, in particular for ethylene business (up by 19.3%). Derivatives sales registered an increased (up by 14.8%) driven by the combined effect of a higher demand and a higher availability of product. Average unit prices decreased by 11.1%, with aromatics price lowered by 7% (benzene), derivatives prices by 7.7% and olefins prices by 17.8% driven by the weakness of the market and overcapacity in Europe.

Intermediates production (3,417 ktonnes) registered an increase of 2.5% from the last year due to increases in aromatics (up by 2.7%) and in derivatives (up by 10.2%). Olefins barely unchanged (up by 0.8%).

Polymers

Polymers revenues (€2,380 million) decreased by €310 million or 11.5% from 2015 due to average unit prices (down by 5.5%) and sold volumes decrease (down by 6.7%), driven by continuing weakness of automotive sectored demand and low prices of Asian producers. These negatives were further exacerbated by the decrease of average styrenics prices (down by 6.3%) and sold volumes down by 9.1%, also due to lower production availability following the Mantova shutdown. Polyethylene volumes (down by 9.8%) and average prices (down by 3.2%) recorded a decrease.

Polymers production (2,229 ktonnes) decreased by 5.8% from 2015. Styrene productions decreased (down by 7.2%) due to the planned Mantova standstill with lower production of styrol (down by 6.4%) and compact polystyrene (down by 11.2%) partly offset by higher productions of ABS/SAN (up by 9.9%). Polyethylene productions decreased (down by 8.6%) driven by scheduled standstills of Ragusa, Ferrara and Dunkerque partly offset by higher productions of HDPE (up by 9.4%). Elastomers productions increased (up by 7.1%), especially in BR segment (up by 15.2%), driven by higher volumes sold compared to 2015.

Capital expenditures

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

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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 minor petrochemical activities and reclamation and decommissioning activities pertaining to certain businesses which Eni exited, divested or shut down in past years; 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 that 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

Technology research and development (R&D) and continuous innovation are key factors in successfully implementing Eni’s business strategies and in supporting mid and long-term performances.

The Company believes that the oil&gas industry will have to face several challenges:

- uncertainty about oil&gas prices and demand;

- limited access to new low-cost hydrocarbon resources, with increasing role of unexplored oil&gas basins;

- need of a more efficient exploitation of conventional fossil sources;

- strong request of stakeholders for a reduction of GHG emissions; and

- safety of operations as a crucial point for business success.

In order to address the above challenges, Eni will pursue the following technological targets in the next future:

-

reducing operational risk and maximizing operational efficiency by development of new tools for prevention and response to blow outs (mechanical barriers and equipment for the capture of subsea oil eruption) and development of tools for vessel maintenance and restoring clogged pipes;

- strengthening technological leadership in exploration by continuously development of proprietary tools;

- maximizing the recovery factor of reservoirs aiming at innovative enhanced oil recovery techniques sustainable also in low oil price scenarios;

- focusing on conversion and processing of stranded gas resources and the development of proprietary technologies in the sector of renewable energies;

- further development of Eni's Green Refinery processes with innovative solution for the conversion of conventional refineries into bio-refineries;

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- formulations of innovative fuels, lubricants and bitumen that comply with European regulations and new motor specifications;

- development of new technologies for the separation, conversion, transportation and utilization of natural gas;

- commitment to transfer quickly the relevant results achieved by research and development to business units, also to the new appointed energy solution one; and

- development of innovative environmental technologies for in situ monitoring and remediation.

In 2016, Eni filed 52 patent applications (33 in 2015).
In 2016, Eni's overall expenditure in R&D amounted to €161 million which were almost entirely expensed as incurred (€176 million in 2015 and €174 million in 2014).

Exploration & Production

• Oxy-Combustion. As part of the zero-flaring strategy, Eni is assessing through a pilot installation at the New Oil Center of Gela, a technology for oxy-combustion, which allows to exploit low calorific tail gas by production of electricity with CO, NOX and hydrocarbons emissions essentially absent.
• MAREnergy. Project aiming at the exploitation of renewable energy in the sea (from waves and wind) to support upstream activities through the development of hybrid solutions capable of minimizing the typical variability of renewable sources in energy generation.
• CO_2 -to-Oil. Project aiming to reduce Eni's carbon footprint using a technology that captures CO_2 to produce a third generation bio-fuel. The emerging technology is based on the cultivation of micro-algae inside bio-reactors in order to produce a bio-algal oil suitable to feed Eni's Green Refineries. The technology pilot plant has being built in Ragusa with start-up scheduled for March 2017.
• Chemical EOR. In 2016, in Egypt three chemical EOR pilots (chemical and low salinity injection) were started in Belayim giant field. First results of the polymer injection in two producing wells confirmed the forecasted improved recovery allowing the booking of additional reserves.
• Drilling Safety Technologies. Project aiming to reduce by two orders of magnitude the risk of blowout occurrence compared to OGP reference. To achieve this goal, new technologies able to improve well integrity both during drilling and well productive life have been developed. In 2016 the first test of a casing valve activated without control line and therefore suitable to be used in subsea wells, was performed; beginning of 2017 a first application in a well will be carried out.

Refining & Marketing

• Eni Green Diesel+. A new premium diesel containing 15% of Hydrotreated Vegetable Oil (HVO), produced in Venice bio-refinery using Eni/UOP's Ecofining™ process, was launched in January with sales increase by about 20%. In November the winter diesel (Eni Green Diesel + Alpino) was also launched.
• Energy Saving Lubricants. In collaboration with GE a new lubricant oil for gas turbines has been developed. Its use will allow Eni to save 790 MMscf of gas and 44'000 tons of CO_2 emissions per year.

Renewable Energy & Environment

• Concentrated Solar Power. Since some years, Eni is engaged in an R&D project for the development of innovative components and engineering solutions for Concentrated Solar Power (CSP) in order to reduce capital investment and operation costs for thermal energy production via solar. In partnership with Massachusetts Institute of Technology it has been developed an innovative, low cost parabolic solar collector, easy to manufacture and assembly. The latter feature will allow the manufacture in the same countries where they will be installed, fostering local employment and economic development. In 2016 a full-scale prototype was built in Politecnico of Milan University.

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• 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. The pilot scale development phase of the technology has been completed.

• Monitoring of Pollution and Remediation of Soils. Eni R&D has been active for years in the development of devices and protocols able to characterize polluted sites and monitor their remediation. Eni in collaboration with Massachusetts Institute of Technology, Consiglio Nazionale delle Ricerche, University of Piemonte Orientale, University of Rome "Tor Vergata" and Syndial, has developed and validated some original passive biomimetic samplers to determine the available fraction of organic contaminants. The devices consist of low-density polyethylene films. In 2016 the application protocol of those devices was validated as official method of analysis by the Italian institute for the research on water (CNR-IRSA).

Energy Transition

In 2016 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 to decarbonize the whole value chain. In particular, the research deals with three areas of interest:

• Natural Gas Transportation and Conversion. Transportation and use of natural gas including the development of materials suitable to take the Adsorbed Natural Gas (ANG) technology to an industrial scale, and the development of processes for the conversion of natural gas to methanol. The latter seen as an important vector for the production of low environmental impact liquid fuels and chemical products (olefins and aromatics).

• Hydrogen Sulfide. Development of new technologies for the separation and use of H_2S, both in fertilizer products and in materials and plastics containing sulfur.

• Carbon Dioxide. Development of new technologies for the separation and use of CO_2 comprising on-board capture of generated CO_2 in motor vehicles and use of CO_2 for production of plastics, fibers and building materials.

Petrochemicals

• 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.

• 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. The Tire Technology Committee has awarded this project with the "Environmental Achievement Award".

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.

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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 incurring significant amounts of expenses to comply with pending regulations in the matter of environmental, health and safety protection and safeguard, particularly 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 2016, the main environmental efforts of the European Union continued to focus on the air quality, energy transition, circular economy and Climate Change matters.

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 123 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.

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 "Winter 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, one of the 10 priorities of the Juncker Commission. The Winter Package has three main goals: putting energy efficiency first (setting a binding 30% energy efficiency target), achieving global leadership in renewable energies and providing a fair deal for consumers. The Package includes some legislative proposals such as revision of Renewable Energy Directive ("RED") - (Directive 2009/28/CE) and revision of the Energy Efficiency Directive. For Eni's strategies and policy on biofuels, a revision of RED has a particular importance. In order to foster the de-carbonization and energy diversification the RED revision proposal introduces an obligation on European transport fuel suppliers to provide an increasing share of renewable and low-carbon fuels, including advanced biofuels, renewable transport fuels of non-biological origin (e.g. hydrogen), waste-based fuels and renewable electricity. The level of this obligation is progressively increasing from 1.5 percent in 2021 (in energy terms) to 6.8 percent in 2030, including at least 3.6 percent of advanced biofuels. It also introduces a cap on the contribution of first generation biofuels (so called "food-based" biofuels) in transport sector towards the EU renewable energy target, starting at 7 percent in 2021 and going down progressively to 3.8 percent in 2030 to minimize the Indirect Land-Use Change (ILUC) impacts.

An important part of EU Climate Strategy is covered by the Emission Trading System (ETS), which is now in the III phase (2013-2020). The Commission has already brought forward key proposals to implement the EU's target to reduce greenhouse gas emissions by 2030. In July 2015, it presented a proposal to reform the EU Emission Trading System (ETS) – phase IV (2021-2030) to ensure the energy sector and energy intensive industries deliver the emissions reductions needed. In summer 2016, the Commission brought forward proposals for accelerating the low-carbon transition in other key sectors of the European economy. To achieve the at least 40% EU target, the sectors covered by the ETS have to reduce their emissions by 43% compared to 2005. 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% currently. Currently around 49% of Eni's direct GHG emissions are included within the Carbon Pricing Scheme by its participation in the EU ETS.

The 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.

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 30 June 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 31 March 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

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Directive (MCP Directive) regulates pollutant emissions from the combustion of fuels in plants with a rated thermal input equal to or greater than 1 megawatt (MWth) and less than 50 MWth. The MCP Directive is a part of the Clean Air Policy Package adopted on December 18, 2013 and it regulates emissions of SO2, 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.

Currently the exchange of views between the Commission and the Technical Working Group on the Large Combustion Plant Best Available Technique reference document (LCP BREF) under the Emission Directive is taking place. By the end of 2017, the adoption of final LCP BREF with revised BAT conclusions is expected. The updated LCP BREF 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.

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. Moreover, in October 2016 the Kigali amendment to the Montreal Protocol (on Substances that Deplete the Ozone Layer) was signed in Rwanda. The Amendment adds powerful greenhouse gases hydrofluorocarbons (HFCs) to the list of substances controlled under the Protocol to be phased down. HFC phasedown is expected to avoid up to 0.5 degree Celsius of global temperature rise by 2100, while continuing to protect the ozone layer.

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. The O&G sector will have to put a significant effort to follow the “circular philosophy” by investing in the innovative technological solutions, optimization of the water use, energy efficiency and the green procurement.

A new integrated EU policy for the Arctic Region has been adopted in 2016. The policy defines the 39 actions focusing on strengthening international cooperation, tackling climate change, enhancing environmental protection and promoting sustainable development.

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 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 European Chemicals Agency (ECHA) how the substance can be safely used and they must communicate the risk management measures to the users. If the risks cannot be managed, Authorities can restrict the use of substances in different ways. Over time, the hazardous substances should be substituted with less dangerous ones. The deadline of 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. There is a transition period until 2015. 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.

Following the incident at the Macondo well in the Gulf of Mexico, the U.S. Government and other governments have adopted more stringent regulations targeting safety and reliable oil&gas operations in the United States and elsewhere, particularly relating to environmental and health and safety protection controls and oversight of drilling operations, as well as access to new drilling areas. Italian Authorities as well have passed legislation with Law Decree No. 128 on June 29, 2010 that introduces certain restrictions to activities for exploring and producing hydrocarbons that have been confirmed and further geographically limited by the successive Law Decree No. 134 of August 7, 2012 and by the Ministerial Decree of September 4, 2013.

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 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.

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- Independent national competent authorities, responsible for the safety of installations, are in charge to verify 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 whose 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 likely 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.

As to 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 2016

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.

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In 2016, 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 304, of which:

- 99 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);
- 18 certifications according to the ISO 50001 standard (certification for an energy management system);
- 103 according to the OHSAS 18001 standard (Occupational Health and Safety management Systems - requirements).

In 2016 the percentage of Eni industrial installations and operating units with a significant HSE risk covered by certification is 97% for the standard OHSAS 18001 and 95% for the ISO 14001 standard.

In 2016, total HSE expenses (including cross-cutting issues such as HSE management systems implementation and certification, etc.) amounted to €1,102 million, increasing by 3.3% from 2015.

Environment. In 2016, Eni incurred total expenditures of €588.65 million for the protection of the environment (with a reduction of 5.9% with respect to 2015). Environmental expenditures are mainly related to remediation and reclamation activities (€233.9 million), waste management (€133.8 million), water management (€62 million), air protection (€47.2 million) and spill prevention (€37.1 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 2016, the new legislation didn't impact significantly procedures already in place for safety in the workplace.

The dissemination of safety culture is a primary target for Eni. In 2016, in order to increase safety's culture in the workforce, awareness-raising initiatives continued. Road Shows and Safety Day were organized with the aim of sharing performance, target, new projects and safety vision between Eni's top management and employees and contractors.

In order to keep developing new awareness raising actions regarding safety at work, in 2016 two new initiatives were launched:

- "Inside Lesson Learned Project" to share lessons learned using video clips made by internal resources and inspired by real events occurred in the company;
- "Eni in Safety 2" to increase safety culture with workshops finalized to discuss safe behaviors, responsibility and leadership in safety. The new projects will be roll out in 2017 involving employees and contractors.

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 will be applied progressively in all operating activities.

Results of efforts to achieve a better safety in all activities brought an improvement of Eni workforce total recordable injury rate (0.35), decreased by 21% compared to 2015.

As to emergency preparedness, Eni has joined the Oil Spill Response-Joint Industry Project (OSR-JIP I & II) launched in December 2011 by International Association of Oil&Gas Producers (IOGP) and International Petroleum Industry

Environmental Conservation Association (IPIECA) and concluded in 2016. The JIP executed the outstanding recommendations from the report produced by the Global Industry Response Group (GIRG) set-up after the Macondo accident.

The 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.

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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 (two are already available in Italian).
Costs incurred in 2016 to support the safety levels of operations and to comply with applicable rules and regulations were €287.8 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.
In 2016, Eni incurred total expenses of €47.9 million, to protect the health of its employees. Eni expects to continue incurring amounts of expenses for health, which will be in line with 2016 levels in future years.
Managing GHG emissions
2016 was a relevant year for the international climate change debate, mainly due to the entry into force of the Paris Agreement on 4th November. The Paris Agreement and its early entry into force represents for Eni a very positive step toward a low carbon energy transition. As a major international energy company, Eni is actively involved to play a leading role to contrast climate change.
Eni recognizes indeed the scientific evidences presented in the IPCC Fifth Assessment Report and the necessity to limit the rise of the global temperature below 2 °C above pre-industrial levels. In line with this long term target, Eni has developed an integrated climate strategy with the aim of advance in the transition towards a low-carbon energy future while fulfilling the growth of energy demand. Eni's climate strategy is composed of three main pillars: reducing and offsetting its greenhouse gas (GHG) emissions; developing a low-carbon portfolio; and committing on renewables

and low carbon R&D.
Regarding the reduction of greenhouse gas (GHG) emissions, since 2010 years Eni reached important results, such as an absolute reduction of 31% in total direct GHG emissions, together with a 30% reduction in the carbon intensity of the Upstream business. These results were mainly driven by flaring down projects, methane monitoring campaign and energy efficiency efforts.

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In order to strengthen this engagement and with a forward looking perspective, in 2015 Eni launched a strategic internal Program on Climate Change aimed at developing a medium and long term roadmap able to drive Eni towards a low carbon future. In line with this Program and the abovementioned strategy, Eni published its targets and established the new "Energy Solutions" business line in order to integrate traditional energy sources with the production of energy from renewable sources.

In particular, by 2025 we have confirmed three main commitments focused on improving our GHG performance: to reduce by -43% vs 2014 the GHG emission intensity of our production, to reach zero routine gas flaring and to abate by 80% the fugitive emissions coming from our Upstream business.

In addition to these operational actions and commitments, Eni actively participates in primary international climate initiatives. In particular, in 2016 Eni contributed to further develop the "Oil and Gas Climate Initiative" (OGCI), a voluntary CEO led initiative launched in 2014 along with other companies in the oil&gas sector (currently, the ten OGCI member companies represent about 25% of global HC production). On November 4, 2016, during a high-level event in London, OGCI CEOs announced an investment of $1 billion over the next ten years to develop and accelerate the deployment of innovative low emissions technologies able to improve the management of GHG emissions and contain climate impacts of the Oil&Gas sector.

In 2016, Eni has continued its efforts in two international Public-Private Initiatives focused on operational efficiency: the "zero routine gas flaring at 2030" program of the World Bank's "Global Gas Flaring reduction partnership" and the "Clean Air and Climate initiative - Oil & Gas Methane Partnership", aimed at reducing methane emissions in the oil&gas value chain. About this important topic, in October 2016 was published the first report of the initiative, with details and information on Eni methane LDAR monitoring campaign during the first year of the initiative.

Thanks to its climate strategy and the ambitious targets for the future, in 2016 Eni has been recognized by the CDP as a global leader for its actions and strategies in response to climate change and was included in the prestigious A-list of CDP. Eni was the only oil & gas major achieving this high recognition.

Another acknowledgment of Eni's climate leadership was the invitation to take part in the works of the Task Force on Climate Related Disclosures of the Financial Stability Board, which has the aim of develop voluntary, consistent climate-related financial risk disclosures for use by companies in providing effective information to investors.

Regarding Eni's own GHG emissions management, with the aim of ensuring a comprehensive, transparent and accurate reporting for GHG emissions, in 2005 Eni introduced its own Protocol for accounting and reporting GHG emissions (GHG Accounting and Reporting Protocol), integrated in 2013 by a procedure on reporting and accounting methodologies on indirect emissions scope 3 types. This procedure was updated in 2015. According to the Eni methodology for accounting and reporting Scope 3 GHG, Eni estimates the indirect GHG emissions generated by several emission categories (e.g. purchased goods and services, use of sold hydrocarbon products, business travel, franchising, etc.) in line with the WBCSD-WRI Protocol "Corporate Value Chain (Scope 3) Accounting and Reporting Standard".

Eni documents are an essential requirement for emissions certification. Indeed, accurate reporting supports the strategic management of risks and opportunities related to GHG, the definition of objectives and the assessment of progress. Eni GHG Protocol has been updated in 2016 to be in compliance with the National and European Guidelines (Regulation No. 601/2012) and with the best practices reference document (American Petroleum Industry Compendium). For safer and more accurate management of GHG emissions and more effective reporting, Eni provided all its business units with a dedicated database, in order to gather and report GHG emissions according to the Protocol and to ensure completeness, accuracy, transparency and consistency of GHG accounting as required by certification needs. In order to improve the Eni accounting and reporting process, Eni confirmed independent verification of its 2016 equivalent CO_2 emissions data (Scope 1, 2 and 3 emissions), as submitted to the CDP, and obtained the verification statement in accordance with ISAE 3410.

In Europe, Eni is subject to the European Union Emission Trading Scheme (EU-ETS) that was established by Directive No. 2003/87/EC. Effective from January 1, 2005, EU-ETS is the largest carbon market in the world for exchanging emission allowances targeting industrial installations with high carbon

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dioxide emissions. The EU-ETS Directive states that any operator, who produces GHG emissions in excess of the amounts allowed on the basis of the national allocation plan, is required to acquire allowances on the market to cover the excess emissions or to pay a penalty.

Currently, Eni participates in the ETS with 41 plants, mostly located in Italy, which collectively represent 49% of all direct GHG emissions generated by Eni's plants worldwide. Due to stricter allocation rules in the third phase (2013-2020) of the Emissions Trading Scheme, Eni has been receiving a lower amount of free allowances in comparison with the second phase (2008-2012). As a consequence, in the next four-year period (2017-2020), Eni will buy on the market an amount of allowances to cover GHG emissions of its industrial plants. The large majority of the deficit is concentrated in the power sector due to European allocation rules.

For additional information on Eni's climate strategy and GHG management, please refer to the latest Eni's Corporate Sustainability Report ("Enifor") or to the Eni's CDP climate change questionnaire response, both published on Eni's website (www.eni.com).

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. See "Regulation of the Italian hydrocarbons industry" and "Environmental matters" for a description of the specific aspects of the Italian regulation and of environmental regulation concerning Eni's exploration and production activities. 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 royalties that are payable in-kind. A license holder is generally required to pay production taxes or royalties, which may be in cash or in-kind. 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. In production sharing agreements, entitlements to production volumes are defined on the basis of contractual agreements drawn up with state oil companies holding the concessions. Such contractual agreements regulate the recovery of costs incurred for the exploration, development and operating activities (Cost Oil) and give entitlement to a portion of the production volumes exceeding volumes destined to cover costs incurred (Profit Oil). A similar scheme to PSA applies to Service and "buy-back" 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.

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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.

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 are equal to 20% for oil&gas, with no exemptions).

Gas & Power

Natural gas market in Italy

Legislative Decree No. 130 of August 13, 2010 containing measures for increasing competition in the natural gas market and transferring the ensuing benefits to final customers and Law Decree of December 23, 2013 containing measures to promote gas market liquidity

In 2011, Legislative Decree No. 130 of August 13, 2010 titled "New measures to improve competitiveness in the natural gas market and to ensure the transfer of economic benefits to final customers" became effective. This new regulation replaced the previous system of gas antitrust thresholds defined by Legislative Decree No. 164 of May 23, 2000 by introducing a 40% ceiling to the wholesale market share of each Italian gas operator who inputs gas into the Italian backbone network. In the frame of Legislative Decree No. 130/2010 Eni built new storage capacity for about 2.64 BCM; as a consequence the above mentioned cap to its market share in Italy rises from 40% to 55%. In the case of violations of the mandatory threshold, Eni is obliged to execute gas release measures at regulated prices up to 4 BCM over a two-year period following the ascertainment of the breach. Access to the new storage capacity was reserved to industrial customers.

The Law Decree of December 23, 2013, converted into Law on February 21, 2014, establishes that any operator with a wholesale market share higher than 10% is obliged to offer on the natural gas forward market a volume of natural gas corresponding to 5% of the annual imported volumes. The obligation to offer should be combined with a corresponding obligation to bid on the same market; the spread between bid and ask prices has to be lower than an amount defined by the Minister of Economic Development, based on a proposal by the AEEGSI. AEEGSI also defines the modalities for the fulfillment of the above mentioned obligation.

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Eni's management is monitoring these issues with a view of assessing any possible financial or economic impact associated with the enacted measures and their evolution. Management also believes that these regulations will increase competition in the wholesale natural gas market in Italy leading to further margin pressures.

Law Decree No. 1 of January 24, 2012 for 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 to:

- enhance competitiveness in gas tariffs to residential customers and in the distribution of refined products. The AEEGSI, in charge with setting pricing mechanisms for supplies to final users, starting from the second quarter of 2012 updated the indexation mechanism by gradually increasing the weight of spot prices in the indexation of the supply costs of gas that previously used to be oil-linked; and

- reform 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 is primarily reserved for the offer to industrial sector of an integrated service (international transport of liquefied natural gas, regasification and storage) allowing them to supply natural gas directly from abroad in the form of liquefied natural gas; and

  - the remaining amount of storage capacity is assigned via auction procedures devoted to the modulation needs.

Based on the principles described above, the Minister of Economic Development and the AEEGSI establish every year the detailed criteria for the allocation of gas storage capacities. In 2016, 1BCM of bundled storage and regasification capacity was offered to the industrial sector.

Negotiation platform for gas trading and gas balancing market

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 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 authorised 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 will be concentrated on the MGAS, managed by GME, as one single platform.
Management believes that these measures have increased, and will further increase, the level of liquidity in the Italian spot market of gas.

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Natural gas prices

Following the liberalization of the natural gas sector introduced in 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 AEEGSI holds a power of surveillance on this matter (see below) under Law No. 481/1995 (establishing the AEEGSI) and Legislative Decree No. 164/2000. Furthermore, the AEEGSI 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 AEEGSI beside their own price proposals.

In 2013, a new tariff regime was enacted for 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 AEEGSI are residential clients (including residential buildings consuming less than 200,000 CM/y). With Resolution No. 196 effective from October 1, 2013, the AEEGSI 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 versus the previous 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 by introducing a pricing component intended to cover the risks and costs of the supplies to wholesalers. Furthermore, it was provided a stability mechanism whereby a wholesaler part of a long-term, take-or-pay gas supply contract may opt for being reimbursed of the possible negative difference between the oil-linked costs of gas supplies and spot prices in the two thermal years following the new regime implementation; conversely, in case spot prices 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. Based on this compensation mechanism, which run out after September 2016, Eni totalled about €160 million of reimbursement over three thermal years, starting in October 2013 and ending in September 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. Furthermore, the new tariff mechanism indexed to TTF (Title Transfer Facility) for residential clients will be applicable until the end of thermal year 2017 - 2018. However, a Law Decree still under discussion at the Italian Parliament, is expected to increase competitive pressure with the abrogation of the tariffs for gas and power effective from July 1, 2018. Referring to the electricity market, residential customers would choose tariffs on the free market, potentially, lower than the regulated ones. For the gas market, similar competitive impact cannot be excluded following the adoption of the same price regulation regime.

Similarly other Regulatory Authorities in European countries where Eni is present have issued regulations referring to hub component in the pricing formulas related to retail clients, as well as measures to boost liquidity and competitiveness in the gas market.

Refining and marketing of petroleum products

Refining. The regulations introduced with Law No. 9/1991 and No. 239/2004 (Article 1, paragraphs 56, 57 and 58) significantly changed the norms introduced in the 1930's that required that any refining activity be handled under a concession from the state. Today an authorization is required to set up new processing and storage plants and for any change in the capacity of mineral processing plants, while all other changes that do not affect capacity can be freely implemented. Another simplification measure was introduced by Law Decree No. 5/2012 that defined mineral oil processing and storage plants as "strategic settlements" that need authorization from the State, in agreement with the relevant Region, and imposes a single process of authorization that must be closed within 180 days. Management expects no material delays in obtaining relevant concessions for the upgrading of the Sannazzaro and Taranto refineries as planned in the medium term.

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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 supply freely 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. Eni expects developments on this issue to further increase pressure on selling margins in the retail marketing of fuels and to reduce opportunities of increasing Eni's market share in Italy.

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) upon the closure of at least 7,000 service stations, 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. With the same goal of renewing the Italian distribution network, Law No. 57 of March 5, 2001 provides that the Ministry of Productive Activities is to prepare guidelines for the modernization of the network, and the Regions shall follow those guidelines in the preparation of regional plans. The subsequent Ministerial Decree of October 31, 2001 establishes the criteria for the closing down of incompatible stations, the approval of the plan, the renewal of the network, the opening up of new stations and the regulations of the operations of service stations on matters such as automation, working hours and non-oil activities. After the approval of Law No. 133/2008, Article 28 of Law Decree No. 98/ 2011 converted into Law No. 111/2011, contains new guidelines for improving market efficiency and service quality and increasing competition. Among other things it provides that within July 6, 2012 all service stations must be provided with self-service equipment and that Regions will update their regulations in order to allow the sale of non-oil products in all service stations. 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 prejudice 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. Management believes that those measures will favor competition in the Italian retail market and support efficient operators.

Petroleum product prices. Petroleum product 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 Productive Activities; 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
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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, 2016, Eni owned 5.2 mmtonnes of oil products inventories, of which 3.6 mmtonnes as "compulsory stocks", 1.4 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 (37%), light and medium distillates (37%), refinery feedstock (19%), fuel oil (5%) and other products (2%) were located throughout the Italian territory both in refineries (80%) and in storage sites (20%).

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 does 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. 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, 2016, there were 218 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, 2016 is provided in Note 48 to the Consolidated Financial Statements.

Item 4A. UNRESOLVED STAFF COMMENTS

None.

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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

		2014	2015	2016
		(€ million)		
Net sales from operations from continuing operations		98,218	72,286	55,762
Operating profit (loss) from continuing operations		8,965	(3,076)	2,157
Net profit (loss) attributable to Eni from continuing operations		1,720	(7,952)	(1,051)
Net profit (loss) attributable to Eni from discontinued operations		(417)	(826)	(413)
Net profit (loss) attributable to Eni		1,303	(8,778)	(1,464)
Net cash provided by operating activities - continuing operations		14,469	12,875	7,673
Capital expenditures - continuing operations		11,178	10,741	9,180
Investments and purchases of consolidated subsidiaries and businesses		408	228	1,164
Shareholders' equity including non-controlling interest at year end		65,641	57,409	53,086
Net borrowings at year end		13,685	16,871	14,776
Net profit (loss) attributable to Eni basic and diluted from continuing operations	(€ per share)	0.48	(2.21)	(0.29)
Net profit (loss) attributable to Eni basic and diluted from discontinued operations		(0.12)	(0.23)	(0.12)
Net profit (loss) attributable to Eni basic and diluted		0.36	(2.44)	(0.41)
Dividend per share	(€ per share)	1.12	0.80	0.80
Ratio of net borrowings to total shareholders' equity including non-controlling interest (leverage)(1)		0.21	0.29	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.

In 2016, Eni reported a net loss pertaining to continuing operations of €1,051 million, with a significant improvement compared to last year's loss of €7,952 million. The operating profit was €2,157 million compared to an operating loss of €3,076 million a year ago. The recovery in oil markets, that has begun in the second half of 2016 favorably affected the full-year results of operations and the assets carrying amounts.

Better market fundamentals were factored in an upward revision to management's long-term price assumption for the benchmark Brent to 70$ per barrel (in 2020 real terms), which was adopted in the financial projections of the 2017-2020 industrial plan and in assessing the recoverability of the Group assets carrying amounts as of December 31,

2016. In 2015, management assumed a long-term Brent price of 65$ per barrel. This upward revision triggered the reversal of prior impairment losses for €1,005 million post-tax at oil&gas properties, which helped mitigate impairment losses due to a lowered outlook for gas prices in Europe and other drivers, as well as other non-recurring charges for an overall negative impact of €831 million.

On the contrary, the FY 2015 result was negatively affected by the recognition of material, post-tax charges of €8.5 billion. Those comprised impairment losses of upstream assets (€3.9 billion) and the

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write-off of deferred tax assets for €1.8 billion due to a lowered profitability outlook. Furthermore, the 2015 charges included the impairment of the Chemical business (€1 billion), the carrying amount of which was aligned to the expected fair value based on a negotiation then ongoing to establish a joint venture with an industrial partner. Subsequently, Eni and the potential buyer failed to close the negotiation. Finally, other extraordinary charges of €1.8 billion were incurred mainly in the G&P segment (for more information about extraordinary charges of G&P segment, see the paragraph "Operating profit by segment").

Nevertheless, the 2016 underlying performance was negatively affected by a continued slump in commodity prices especially in the first half of the year which determined y-o-y declines in average crude oil prices (down by 16.7%, from 52.5 $/b reported in 2015, to 43.7 $/b in 2016), gas prices (down by 28.2%) and refining margins (down by 49.4%). These declines drove a 23% reduction in the Group consolidated turnover. Other factors negatively affecting the performance were a four and half-month shutdown of the Val d'Agri oil complex in Italy and lower one-off gains in the Gas&Power segment in connection with an ongoing renegotiation process of its long-term gas supply contracts. Management implemented a number of initiatives to withstand the negative trading environment, including tight investment selection, with capex down by 15% (19% y-o-y at constant exchange rates), control of E&P operating expenses (down by 17%), optimizations of plant setup at refineries and chemical plants, savings on energy consumptions and logistic costs and G&A cuts. All these measures improved operating profit by around €1.7 billion. Finally, income taxes declined by €1,186 million due to the above mentioned extraordinary drivers. The tax rate was affected by the high relative incidence on taxable profit of results earned at PSA contracts, which are characterized by higher-than-average rates of taxes.

Overall management estimated that the increase in the Group operating results of approximately €5.2 billion (from an operating loss of €3.08 billion in 2015 to a profit of €2.16 billion in 2016) was due to the following factors:

- a positive €1.7 billion gain associated with efficiency initiatives, cost reductions, lower depreciation and amortization, as well as a decreased exploration expenditure;

- a positive €8.6 billion effect due to lower asset impairments and lower other extraordinary charges as well as a lower inventory holding valuation allowance;

These positives were partly offset by:

- a negative €3.3 billion impact due to lower commodity prices and margins;

- a negative €0.6 billion effect due to the four and a half months shutdown of operations at the Val d'Agri profit centre (see Item 4 – Exploration & Production – Eni's principal oil&gas properties) and in the Gas & Power segment lower one-off gains related to the renegotiations of gas contracts;

- a negative €1.2 billion associated with the accounting of Saipem as discontinued operation in 2015. Due to this accounting method, the 2015 result of the continuing operations benefitted from the elimination upon consolidation of then intercompany purchases of capital goods and other services, mainly oilfield services to the E&P segment. This reflected the fact that in 2015 for accounting purposes Saipem was a fully consolidated subsidiary as Eni still exercised control at the balance sheet date. In 2016 due to the loss of control, Saipem was derecognized from the beginning of the year. Therefore, in 2016 the purchases of capital goods and services from Saipem were accounted as expenses from third parties incurred by the continuing operations.

In FY 2016, the Group net loss pertaining to Eni's shareholders amounted to €1,464 million. This included a loss in the discontinued operations of €413 million relating to an impairment charge taken to align the book value of Eni's retained interest in Saipem to its fair value, equal to the market capitalization at the date of loss of control (January 22, 2016) with a charge of €441 million.

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The table below sets forth for the reported periods details of certain, identified gains and charges included in net loss. These gains and charges mainly related to inventory holding gains and losses, asset impairments, reversals of prior impairment losses, estimate revisions, risk and other provisions, write downs of deferred tax assets, capital gains on investments and other tangible assets.

	Year ended December 31,		
Eni Group	2014	2015	2016
	(€ million)		
(Profit) loss on inventory	1,460	1,136	(175)
Environmental provisions	179	225	193
Impairment losses (impairment reversals), net	1,272	6,534	(459)
Impairment of exploration projects		169	7
Net gains on disposal of assets	(24)	(407)	(10)
Risk provisions	(35)	211	151
Provision for redundancy incentives	4	30	47
Fair value gains/losses on commodity derivatives	(16)	164	(427)
Reclassification of currency derivatives and translation effects to management measure of business performance	229	(63)	(19)
Estimate revision of revenues accrued in the gas retail business		484	161
Valuation allowance of disputed receivables			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	303	301	279
Total net charges (gains) in operating profit	3,372	8,784	158
Capital gains on disposal of investments	(159)	(33)	(57)
Write downs of investments and financing receivables	(38)	506	483
Write down of deferred tax assets/utilization of deferred tax liabilities	1,045	1,740	170
Gain on a tax dispute relating to the Libyan Tax	(824)		
Tax effects on the above listed items and other items	(13)	(1,321)	(98)
Tax effects on (profit) loss on inventory	(452)	(354)	55
Net (charges) gains in net profit	2,931	9,322	711
Net (charges) gains attributable to non-controlling interest	452	53	
Net (charges) gains attributable to Eni	2,479	9,269	711

In evaluating the Company's underlying performance and with the objective of better explaining year-on-year changes, management has considered to separate from the other drivers of the Group performance the impact of the following items:

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the above listed gains and charges amounting to a post-tax loss of €9,269 million and €711 million in 2015 and in 2016, respectively, which include an inventory holding post-tax loss of €782 million in 2015 and a post-tax profit of €120 million in 2016; and

- profit on intercompany transactions with the discontinued operations for €514 million in 2015, which are eliminated upon consolidation.

On that basis, management has calculated a Non-GAAP measure of operating profit that would amount to €2,315 million for 2016, down by €2,171 million from 2015. A low commodity price environment accounted for a decline of €3.3 billion, while a four-month and half shutdown of operations at Val d'Agri and lower non-recurring gains in G&P accounted for €0.6 billion. Efficiency gains and a reduced cost base, mainly in the E&P segment, helped mitigate the negative factors and improved the performance by €1.7 billion. The corresponding Non-GAAP measure of net loss would amount to €340 million, down by €1,143 million from 2015 due to a lower operating performance, declining results from equity-accounted entities reflecting weak commodity prices and a higher Group tax rate mainly driven by the E&P segment.

Adjusted operating profit (or loss) and adjusted net profit (or loss) provide management with an understanding of the results from our base operations by excluding the effects of certain disposals and special 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 a more comparable measure as they adjust for disposals and special charges or gains not reflective of the normal trend results of 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 judgement, book value of assets, capital structure and the method by which assets were acquired, among other factors.

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,		
	2014	2015	2016
	(€ million)		
GAAP measure of operating profit of continuing operations	8,965	(3,076)	2,157
Identified net charges and inventory holding gains and losses	3,372	8,784	158
Elimination upon consolidation of intercompany transactions with discontinued operations	(1,114)	(1,222)	
Non-GAAP measure of operating profit of continuing operations	11,223	4,486	2,315
GAAP measure of net profit of continuing operations	1,720	(7,952)	(1,051)
Identified net charges and inventory holding gains and losses	2,479	9,269	711
Elimination upon consolidation of intercompany transactions with discontinued operations	(476)	(514)	
Non-GAAP measure of net profit of continuing operations	3,723	803	(340)
GAAP measure of net cash provided by operating activities from continuing operations	14,469	12,875	7,673
Elimination upon consolidation of intercompany transactions with discontinued operations	(925)	(720)	
Non-GAAP measure of net cash provided by operating activities from continuing operations	13,544	12,155	7,673

Hydrocarbons production was substantially stable y-o-y in spite of a 19% reduction in capital expenditures. Project re-phasing and the renegotiation of contracts for the supply of plants and equipment drove the capital reduction. The Group replaced 193% of the reserves produced due to progress in development activities, exploration success and the FID taken at the Zohr gas project, off Egypt. The effectiveness of our exploration activity was proven by the finalization of the transactions to dispose of a 40% interest in the Zohr discovery, with a value to Eni of approximately €2 billion, which includes the reimbursement of the cost incurred in 2016 for developing and operating activities. Even discounting the Zohr 40% disposal, our proved reserve replacement ratio would remain significant at 139%.

In 2016, we started several new capital projects, including Goliat in the Barents Sea and Kashagan in Kazakhstan. In 2017, we expect new large field start-ups, including the OCTP oilfield in Ghana, the East Hub project in Angola, started up in February 2017, the Jangkrik gas complex in Indonesia and the Zohr project. In 2017, we forecast a production growth of approximately 5% due to the full ramp-up of fields started in 2016 and new projects coming on stream.

In 2016, net cash provided by operating activities from continuing operations amounted to €7,673 million. The closing of the Saipem transaction generated approximately €5.2 billion of proceeds and was

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one of the main drivers in the Group's net borrowings reduction y-o-y; other disposals amounted to €0.6 billion. These inflows funded part of financial requirements for capital expenditure (€9,180 million), the payment of Eni's dividend (the final dividend for fiscal year 2015 and the 2016 interim dividend totaling €2,881 million) and finally the amount cashed out to subscribe the share capital increase of Saipem (€1,069 million). Management also assessed the Group net cash provided by operating activities excluding the negative effect of the Val d'Agri shutdown, which amounted to €0.2 billion, the reimbursement in-kind of certain financing receivables due by a joint venture to Eni with trading receivables, which negatively impacted the operating cash flow for €0.3 billion, while changes in working capital due to the sale of the 40% interest in Zohr would have improved cash flow by €0.1 billion. On that basis, net cash provided by operating activities would have funded a large part of 2016 capital expenditure of €9.2 billion, particularly when considering that approximately €0.5 billion of capex incurred in the year will be reimbursed to Eni because of the Zohr transaction in 2017. The Group's net debt decreased by €2,095 million to €14,776 million. The Group ratio of finance debt to total equity at year-end 2016 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 2016 decreased to 0.28 down from 0.29 at the end of 2015 and was below the 0.30 threshold set by management in spite of a two-year downturn in crude oil prices.

In 2017, we are projecting a capital expenditure budget of approximately €7.6 billion, 18% lower than in 2016 at constant exchange rates, while confirming an increase in production by approximately 5% compared to 2016.

We also plan to preserve our liquidity by leveraging on the timely development of capital projects in the Exploration & Production in order to achieve the scheduled time-to-market of our reserves, on cost efficiencies across all businesses and on strengthening profitability at our Gas & Power and Refining & Marketing and Chemical segments.

We plan to generate additional funds through our asset disposal program, which will mainly comprise the dilution of our working interests in certain of our exploration discoveries. In March 2017, we signed a preliminary agreement to divest to ExxonMobil a stake of 25% in our exploration asset Area 4 in Mozambique for a cash consideration of $2.8 billion.

Finally, notwithstanding a weak commodity prices environment, we are planning to confirm our base dividend of €0.8 per share for fiscal year 2017.

Trading environment

	2014	2015	2016
Average price of Brent dated crude oil in U.S. dollars(1)	98.99	52.46	43.69
Average price of Brent dated crude oil in euro(2)	74.48	47.26	39.47
Average EUR/USD exchange rate(3)	1.329	1.110	1.107
Standard Eni Refining Margin (SERM)(4)	3.2	8.3	4.2
Euribor - three month euro rate %(3)	0.21	(0.02)	(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 are, 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

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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 2016, the trading environment was characterized by a continued weakness in crude oil prices, particularly in first half of the year due to oversupplies. In the second half of the year, market conditions started to improve and oil prices recovered part of first-half losses. This was driven by a better balance between global demand and supplies on the back of the agreement reached by OPEC Countries at the end of November 2016 to reduce the output of the cartel, joined also by certain non OPEC countries (among which Russia). Despite this recovery, the average price for the Brent crude oil benchmark declined by 17% y-o-y. A weak commodity scenario (mainly in the United States and in Europe) affected gas realizations on equity production, also reflecting time lags in oil-linked price formulas.

Eni’s refining margins (Standard Eni Refining Margin - SERM) that represents the benchmark for the level of profitability of Eni’s refineries before fixed cash expenses, halved from a year ago (down by 49.4%) to $4.2 per barrel due to structural headwinds in the European refining industry. The Company managed to reduce its breakeven margin and to align it with the current trading environment, exceeding the planned breakeven target of $4.5 per barrel.

Gas prices in the Company’s Gas & Power segment declined y-o-y driven by continued oversupplies, weak demand growth and the constraints connected minimum off-take obligations provided by long-term gas purchase contracts with take-or-pay clause. In addition to declining spot sale prices, in 2016 also the differential between Italian hub prices and European hub ones (PSV vs. TTF) contracted and negatively affected the G&P segment’s results.

The exchange rate of euro against the dollar was 1.107, stable compared to the average exchange rate recorded in 2015.

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 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 summary of significant estimates is provided in “Item 18 – note 6 – of the Notes on Consolidated Financial Statements”.

2014-2016 Group results of operations

Adoption of the Successful effort method (SEM)

Effective January 1, 2016, management elected to change the criterion to recognize exploration expenses adopting the successful-effort-method (SEM). The successful-effort method is largely adopted by oil&gas companies, to which Eni is increasingly comparable given the recent re-focalization of the Group activities on its core upstream business. Under the SEM, geological and geophysical exploration costs are recognized as an expense as incurred. Costs directly associated with an exploration well are initially capitalized as an unproved tangible

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asset until the drilling of the well is completed and the results have been evaluated. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an unproved asset. If it is determined that development will not occur then the costs are expensed. Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons are initially capitalized as an unproved tangible asset. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to proved property.

In accordance to IAS 8 “Accounting policies, Changes in accounting estimates and Errors”, the retrospective application of the SEM has required adjustment of the opening balance of several items as of January 1, 2014. Specifically, the opening balance of the carrying amount of property, plant and equipment was increased by €3,524 million, intangible assets by €860 million and retained earnings by €3,001 million. Other adjustments related to deferred tax liabilities and other minor line items.

In the table below, the key line items of the profit and loss and balance sheet are presented with reference to the full years 2014 and 2015 previously reported, and as restated in accordance with the application of SEM and the cessation of the accounting of Eni’s Chemical segment as a disposal group held for sale. In 2015, the Chemical segment was presented as discontinued operations due to an ongoing negotiation at the 2015 balance sheet date designed to establish an industrial joint venture with a third party who had expressed an interest in acquiring a majority stake of Eni’s chemical arm. In 2016 Eni and the potential buyer could not come to an agreement and the accounting of Versalis as discontinued operation ceased with retroactive effects to the date of initial recognition as discontinued operations.

	AS PREVIOUSLY REPORTED	AS RESTATED
	(€ million)	
Full year 2014		
Operating profit (loss) - continuing operations	7,585	8,965
Operating profit (loss) E&P	10,766	10,727
Net profit (loss) attributable to Eni’s shareholders - continuing operations	101	1,720
Total assets	146,207	150,366
Eni’s shareholders equity	59,754	63,186
Net cash flow	1,183	1,183
Full year 2015		
Operating profit (loss) -	(2,781)	(3,076)

continuing operations		
Operating profit (loss) E&P	(144)	(959)
Net profit (loss) attributable to Eni's shareholders - continuing operations	(7,680)	(7,952)
Total assets	134,792	139,001
Eni's shareholders equity	51,753	55,493
Net cash flow	(1,414)	(1,405)

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Overview of the profit and loss account for three years ended December 31, 2014, 2015 and 2016

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,		
	2014	2015	2016
	(€ million)		
Net sales from operations	98,218	72,286	55,762
Other income and revenues(1)	1,079	1,252	931
Total revenues	99,297	73,538	56,693
Operating expenses	(80,333)	(59,967)	(47,118)
Other operating (expense) income	145	(485)	16
Depreciation, depletion and amortization	(7,676)	(8,940)	(7,559)
Impairment losses (impairment reversal), net	(1,270)	(6,534)	475
Write-off	(1,198)	(688)	(350)
OPERATING PROFIT (LOSS)	8,965	(3,076)	2,157
Finance income (expense)	(1,167)	(1,306)	(885)
Income (expense) from investments	476	105	(380)
PROFIT (LOSS) BEFORE INCOME TAXES	8,274	(4,277)	892
Income taxes	(6,466)	(3,122)	(1,936)
Net profit (loss) - continuing operations	1,808	(7,399)	(1,044)
Net profit (loss) - discontinued operations	(949)	(1,974)	(413)
Net profit (loss)	859	(9,373)	(1,457)
Attributable to:			
Eni's shareholders:	1,303	(8,778)	(1,464)
- continuing operations	1,720	(7,952)	(1,051)
- discontinued operations	(417)	(826)	(413)
Non-controlling interest:	(444)	(595)	7
- continuing operations	88	553	7
- discontinued operations	(532)	(1,148)	

(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,		
	2014	2015	2016
	(%)		
Operating expenses	81.8	83.0	84.5
Depreciation, depletion, amortization, impairments (reversal of assets) net, write-off	10.3	22.4	13.3

OPERATING PROFIT	9.1	(4.3)	3.9

2016 compared to 2015. See management discussion under paragraph “Executive summary” on page 90 for an overview of the Group’s results from continuing operations.

Net loss attributable to Eni’s shareholders including both continuing operations and discontinued operations amounted to €1,464 million for 2016. The loss of the discontinued operations pertaining to Eni’s shareholders (€413 million) was affected by the recognition of a charge of €441 million due to the

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alignment of Eni’s retained interest in Saipem with its market value the date of the loss of control (January 22, 2016). The market value of the retained interest in the former subsidiary was the carrying amount of such interest upon initial recognition for the subsequent accounting under the equity method (€564 million to which a share capital increase of €1,069 million is to be added).

2015 compared to 2014. Net loss attributable to Eni’s shareholders including both continuing operations and discontinued operations amounted to €8,778 million for 2015. The loss of the discontinued operations pertaining to Eni’s shareholders was negatively affected by the recognition of an impairment loss on the disposal group Saipem the net assets of which were aligned to the lower of their carrying amounts and fair value. Eni’s net asset in Saipem were aligned to the share price at the reporting date, recording an impairment charge of €393 million. Partly offsetting, a fair-valued derivative gain of €49 million was recorded for Saipem due to the difference between the transaction price (€8.39 per share) and the market price at the reporting date (€7.49 per share) relating the stake under disposal.

Discontinued operations

The table below sets forth net profit (loss) attributable to discontinued operations for the periods indicated.

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Net profit - discontinued operations	(949)	(1,974)	(413)
attributable to:			
- Eni	(417)	(826)	(413)
- non-controlling interest	(532)	(1,148)	

Based on the accounting of IFRS 5 for disposal groups, gains and losses pertaining to the discontinued operations include only those earned from transactions with third parties. Until such time as Saipem was a subsidiary of the Eni Group (i.e. end of the reporting period 2015), gains and losses on intercompany transactions have been eliminated upon consolidation. These comprised mainly revenues earned by Saipem for the supply of capital goods and maintenance services to Eni’s Group companies, which were eliminated upon consolidation, positively affecting results of the continuing operations, while negatively affecting the results of operations of the discontinued operations. This effect did not recur in 2016 due to the derecognition of Saipem effective January 1, 2016. Furthermore, the 2015 loss from discontinued operations included the alignment of Saipem’s net assets to its market capitalization at the balance sheet date leading to a loss of €393 million.

Analysis of the line items of the profit and loss account of continuing operations

a) Total revenues

Eni’s revenues from continuing operations were €56,693 million, €73,538 million and €99,297 million for the years ended December 31, 2016, 2015 and 2014, respectively. Total revenues consist of net sales from operations and other income and revenues. Eni’s net sales from operations from continuing operations amounted to €55,762 million, €72,286 million and €98,218 million for the year ended December 31, 2016, 2015 and 2014, respectively, and its other income and revenues totaled €931 million, €1,252 million and €1,079 million, respectively, in these periods.

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Net sales from operations from continuing operations

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

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Exploration & Production	28,488	21,436	16,089
Gas & Power	73,434	52,096	40,961
Refining & Marketing and Chemicals	28,994	22,639	18,733
Corporate and other activities	1,429	1,468	1,343
Impact of unrealized intragroup profit elimination(1)	54		
Consolidation adjustment(2)	(34,181)	(25,353)	(21,364)
NET SALES FROM OPERATIONS	98,218	72,286	55,762

(1)

This item mainly concerned intra-group sales of goods, services and capital assets recorded at period end in the assets of the purchasing business segment.

(2)

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 46 – of the Notes on Consolidated Financial Statements" for a breakdown of intragroup sales by segment for the reported years.

2016 compared to 2015. Eni's net sales from operations (revenues) from continuing operations for 2016 (€55,762 million) decreased by €16,524 million from 2015 (or down 22.9%) primarily reflecting lower realizations on oil, products and natural gas due to significantly lower commodity prices. Changes in sales volumes of products sold were immaterial.

Revenues generated by the Exploration & Production segment (€16,089 million) decreased by €5,347 million (or down by 24.9%). This was due to lower average realizations on equity hydrocarbons (down by 20.1% on average in dollar terms) driven by declining prices for the marker Brent (down by 16,7%) and gas benchmarks in Europe, in the United States and elsewhere also considering the time lags in oil-linked formulas. The reduction was also negatively affected by the Val d'Agri shutdown, which lasted four and half months. The negative price impact was mainly recorded at concession contracts, while PSA contracts are insulated from the scenario due to the cost recovery mechanism.

Revenues generated by the Gas & Power segment (€40,961 million) decreased by €11,135 million (or down by 21.4%). The reduction reflected lower gas and power selling prices as well as lower commodity prices in the business of crude oil and refined products trading, which impact was however offset at the operating profit level by a corresponding decrease in the supply costs of the commodities. Furthermore, revenues were also negatively affected by a downward revision of revenues accrued on the sale of gas and power to retail customers in Italy (€161 million) dating back to past reporting periods prior to 2015.

Revenues generated by the Refining & Marketing and Chemical segment (€18,733 million) decreased by €3,906 million (or down by 17.3%) mainly reflecting lower average selling prices driven by weaker commodity prices. The average selling prices in the Chemical business declined by 10% due to lower price of polymers (down by 6.7% and down by 6.3% the average price of elastomers and styrenics, respectively), reflecting the impact of scenario and competitive pressure.

2015 compared to 2014. Eni's net sales from operations (revenues) from continuing operations for 2015 (€72,286 million) decreased by €25,932 million from 2014 (or down by 26.4%) primarily reflecting lower realizations on oil, products and natural gas in dollar terms due to significantly lower commodity prices. This negative trend was partially offset by a favorable exchange rate environment and increased sales volumes in the Exploration & Production segment, as well as higher Eni's refining throughputs.

Revenues generated by the Exploration & Production segment (€21,436 million) decreased by €7,052 million (or down by 24.8%) due to lower oil&gas realizations in dollar terms (down by 44.3% on average) reflecting the lower price for the marker Brent and lower gas prices in Europe and in the United States.

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Lowered hydrocarbons realizations in dollars reduced reported revenues by approximately €12 billion. This effect was partly offset by favorable exchange rate differences in translating dollar-denominated revenues into the euro representation currency for €3.3 billion and higher production volumes sold for €1.6 billion. The negative price impact was mainly recorded at concession contracts, while PSA contracts are insulated from the scenario due to the cost recovery mechanism.

Revenues generated by the Gas & Power segment (€52,096 million) decreased by €21,338 million (or down by 29.1%). The reduction reflected lower commodity prices in the business of crude oil and refined products trading, which impact was however offset by a corresponding decrease in the supply costs of the commodities. Furthermore, gas selling prices continued to deteriorate reflecting, in addition to the commodity price environment, weak gas demand and increasing competitive pressure. Revenues were also impacted an estimate revision of revenues accrued on the sale of gas (€346 million) and power (€138 million) to retail customers in Italy dating back to the past reporting periods.

Revenues generated by the Refining & Marketing and Chemicals segment (€22,639 million) decreased by €6,355 million (or down by 21.9%) mainly reflecting lower average sales prices products driven by lower commodity prices.

b) Operating expenses

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

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Purchases, services and other	77,404	56,848	44,124
Payroll and related costs	2,929	3,119	2,994
Operating expenses	80,333	59,967	47,118

2016 compared to 2015. Operating expenses from continuing operations for 2016 (€47,118 million) decreased by €12,849 million y-o-y, down by 21.4%, primarily reflecting lower 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 €360 million relating mainly to environmental provisions ((€436 million in 2015). Payroll and related costs (€2,994 million) decreased by €125 million from 2015, down by 4%, due to lower average number of employees outside Italy.

2015 compared to 2014. Operating expenses from continuing operations for 2015 (€59,967 million) decreased by €20,366 million from 2014, down by 25.4%, primarily reflecting lower supply costs of raw materials (natural gas under long-term contracts, refinery feedstock and hydrocarbons purchased for resale) due to underlying trends in the energy scenario partially offset by negative exchange rate effects. Purchases, services and other costs included €436 million relating to environmental and other risk provisions, net of reversal of unused provisions. In addition, an allowance to the provision for doubtful accounts was recognized in 2015 in the retail Gas & Power business to take in account an estimate revision of revenues accrued on the sale of natural gas and electricity (€226 million; €130 million for gas sale and €96 million for electricity) to retail customers in Italy dating back to past reporting periods. Payroll and related costs (€3,119 million) increased by €190 million from 2014, up by 6.5%, due to the appreciation of the U.S. dollar against the euro. These effects were partially offset by lower average number of employees.

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c) Depreciation, depletion, amortization, impairments (impairments reversal) net and write-off

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

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Exploration & Production	6,916	8,080	6,772
Gas & Power	335	363	354
Refining & Marketing and Chemicals	381	454	389
Corporate and other activities	70	71	72
Impact of unrealized intragroup profit elimination(1)	(26)	(28)	(28)
Total depreciation, depletion and amortization	7,676	8,940	7,559
Impairment losses	1,334	6,537	1,067
Reversals of impairment losses	(64)	(3)	(1,542)
Write-off	1,198	688	350
Total depreciation, depletion, amortization, impairment losses (impairment reversals), net and write off	10,144	16,162	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.

2016 compared to 2015. In 2016, depreciation, depletion and amortization charges (€7,559 million) decreased by €1,381 million from 2015, or 15.4%, mainly in the Exploration & Production segment (with a decrease of €1,308 million) reflecting lower capital expenditures of the year (down by 16.2%) and the lower carrying amounts of certain oil&gas properties following the impairment losses booked in 2015 (€5,212 million).

In 2016, the Group recorded reversals of prior impairment losses at oil&gas properties for €1,440 million. These were determined by an upward revision to the long-term price of the benchmark Brent to 70 $/barrel, up from the previous 65 $/barrel assumption, which drove the financial projections of the 2017-2020 industrial plan and the recoverability of oil&gas assets carrying amounts in the 2016 financial statements. These reversals were partly offset by impairment losses related to gas properties in the upstream business driven by a lowered price outlook in Europe and other oil&gas properties due to contractual changes, reserves revision and a higher country risk (overall amount of €756 million). Finally, investments made for compliance and stay-in-business purposes were fully impaired at cash generating units previously written-off in the Refining & Marketing and Chemicals segment, which were confirmed to lack any prospects of profitability (€104 million), while the Gas&Power segment recorded €81 million related to a gas transport infrastructure and LNG carriers.

The write-off amounting to €350 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. The item also comprised the write-off of the damaged units of the EST conversion plant at the Sannazzaro Refinery due to the accident occurred in December 2016 (€193 million).

2015 compared to 2014. In 2015, depreciation, depletion and amortization charges (€8,940 million) increased by €1,264 million from 2014, or 16.5%, mainly in the Exploration & Production segment (increasing by €1,164 million) reflecting the appreciation of the U.S. dollar against the euro and higher production volumes.

In 2015, impairment charges of €6,534 million related to oil&gas properties (€5,212 million) driven by the projections of lower hydrocarbon prices in the medium to long-term, which affected their recoverable amounts. The most notable impairments refer to certain assets, which were acquired by the Group following business combinations in previous reporting periods (Algeria, Congo and Turkmenistan) and to CGUs which are currently operating in high-cost areas (United States, United Kingdom, Norway and Angola). Furthermore, investments made for compliance and stay-in-business purposes were written off at

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cash generating units previously written-off in the Refining & Marketing and Chemicals segment, which were confirmed to be lacking any prospects of profitability. Finally, impairment losses were recorded at the Group power plants in the G&P segment due to a weak margins scenario. The amount of write-offs of exploration project was also mainly driven by management's decision to cease committing funds to certain projects in light of the deteriorated oil price environment.

d) Operating profit (loss) by segment

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

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Exploration & Production	10,727	(959)	2,567
Gas & Power	64	(1,258)	(391)
Refining & Marketing and Chemicals	(2,811)	(1,567)	723
Corporate and other activities	(518)	(497)	(681)
Impact of unrealized intragroup profit elimination	1,503	1,205	(61)
Operating profit (loss)	8,965	(3,076)	2,157

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

	Year ended December 31,		
	2014	2015	2016
	(%)		
Exploration & Production	37.7	(4.5)	16.0
Gas & Power	0.1	(2.4)	(1.0)
Refining & Marketing and Chemicals	(9.7)	(6.9)	3.9
Group	9.1	(4.3)	3.9

Exploration & Production. In 2016, the Exploration & Production segment reported an operating profit of €2,567 million, with an increase of €3,526 million from the operating loss of €959 million reported in 2015. This change mainly reflected the impairment charges of €5,212 million recorded in 2015 due to a downward revision of the oil scenario, while in 2016 net impairment reversals of €684 million were recorded due to a hike in management long-term oil price assumptions.

In 2016, the Company's liquids and gas realizations decreased on average by 20.1% in dollar terms, driven by a decline in international oil prices for market benchmarks (Brent crude prices decreased by 16.7%). Eni's average oil realizations decreased on average by 15.4%. Eni's average gas realizations decreased by 28.2% and were negatively impacted by the weak scenario and time lags in oil-linked formulas.

In 2015, the Exploration & Production segment reported an operating loss of €959 million, with a decrease of €11,686 million from 2014. The decline was principally due to reduced oil&gas realizations in dollar terms (down 44.3% on average) and increased impairment charges (up by €4,361 million). The negative impacts were only partially offset by a favorable exchange rate environment, higher production volumes and reduced operating expenses.

In 2015, the Company's liquids and gas realizations decreased on average by 44.3% in dollar terms, driven by a decline in international oil prices for market benchmarks (Brent crude price decreased by 47%). Eni's average oil realizations decreased on average by 47.8%. Eni's average gas realizations decreased by 33.8%.

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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 core business performance across reporting periods. Excluding the below-listed gains and charges, the E&P segment reported a Non-GAAP operating profit of €2,494 million, with a decrease of €1,688 million from 2015, or 40.4%. The decrease was driven by a weak commodity environment which drove reduced oil&gas realizations in dollar terms (down by 20.1% on average) and a four-month and half production shutdown at the Val d'Agri site. These negatives were partly offset by higher production in other areas and lower operating expenses and DD&A driven by continuing efficiency initiatives and optimization, as well as lower carrying amounts of oil&gas assets due to the impairments recorded in 2015.

	Year ended December 31,		
	2014	2015	2016
Exploration & Production	(€ million)		
GAAP operating profit (loss)	10,727	(959)	2,567
Impairment losses (impairment reversals), net	853	5,212	(684)
Risk provisions	(5)	0	105
Impairment of exploration projects(1)		169	7
Net gains on disposal of assets	(70)	(403)	(2)
Provision for redundancy incentives	24	15	24
Fair value gains/losses on commodity derivatives	(28)	12	19
Reclassification of currency derivatives and translation effects to management measure of business performance	6	(59)	(3)
Valuation allowance of disputed receivables			410
Other	172	195	51
Total gains and charges	952	5,141	(73)
Non-GAAP operating profit (loss)	11,679	4,182	2,494

(1)
Management has separately disclosed the results of the impairment review conducted at certain ongoing exploration projects where management ceased its commitment due to a deteriorated commodity price environment.

Gas & Power. In 2016, the Gas & Power segment reported an operating loss of €391 million, improving by €867 million compared to 2015 when the segment reported an operating loss of €1,258 million. The 2015 result was negatively affected by a downward estimate revision of revenues accrued on the sale of gas and power (€484 million) to retail customers in Italy dating back to past reporting periods and the establishment of a provision for the above mentioned accruals (€226 million). In 2016, accrued revenues were revised lower by €161 million relating reporting periods prior to 2015. Furthermore, commodity derivatives lacking criteria for being accounted as hedges generated approximately €500 million of higher gains in 2016.

In 2015, the Gas & Power segment reported an operating loss of €1,258 million, down by €1,322 million from 2014 when the segment reported an operating profit of €64 million. The change reflected one-off gains associated to certain contracts renegotiation recorded in 2014, as well as the negative outcome of a commercial arbitration in 2015. Furthermore, the 2015 result was affected by an estimate revision of revenues accrued on the sale of gas and power (€484 million) to retail customers in Italy dating back to past reporting periods and the establishment of a provision for the above mentioned accruals (€226 million). Management estimates revenues accrued in the retail sales business utilizing data communicated by market operators that are responsible for verifying actual consumptions with the possibility to review their measurements until the fifth subsequent reporting period.

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 loss of €390 million, with a decline of €264 million from 2015. This negative trend was due to lower margins in the LNG business on sales to premium markets and lower one-off benefits from contracts renegotiations, partly offset by logistics costs optimizations and better performance in trading activities. The retail segment reported lower results due to unusual winter weather conditions.

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The items excluded from GAAP operating profit in determining the Non-GAAP measure of profitability mainly include certain 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 which underlying physical transaction has yet to be settled with the delivery of the underlying commodity. Furthermore, albeit 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 alignment differences of our trade payables and receivables as part of the underlying business performance. Finally, management has excluded from GAAP operating profit the remeasurement of revenues accrued in the retail gas and power business because they relate to past reporting periods.

	Year ended December 31,		
	2014	2015	2016
Gas & Power	(€ million)		
GAAP operating profit (loss)	64	(1,258)	(391)
(Profit) loss on inventory	(119)	132	90
Impairment losses	25	152	81
Risk provisions	(42)		
Allowance for doubtful accruals in the retail G&P		226	17
Provision for redundancy incentives	9	6	4
Fair value gains/losses on commodity derivatives	(38)	90	(443)
Reclassification of currency derivatives and translation effects to management measure of business performance	205	(9)	(19)
Revision of estimate revenues accruals in the retail G&P		484	161
Other	64	51	110
Total gains and charges	104	1,132	1
Non-GAAP operating profit (loss)	168	(126)	(390)

Refining & Marketing and Chemicals. In 2016, the Refining & Marketing and Chemicals segment reported an operating profit of €723 million, reversing an operating loss of €1,567 million reported in 2015. The improvement of €2,290 million was mainly due to lower assets impairments because a €1 billion charge was recognized in 2015 at the Chemical business to align its carrying amount with the expected fair value based on a sale transaction then ongoing designed to establish an industrial joint venture. Furthermore, in 2015 an inventory write-down of €877 million (pre-tax) was accounted for in the profit and loss because of the fall in oil commodity prices to align the net realizable value of the inventories to prices current at the balance sheet date. In 2016, following a late-year recovery in price scenario, the write down resulted in a gain on stock. The 2016 operating profit in the Refining & Marketing and Chemicals segment was also negatively affected by the write-off related to the EST conversion plant, at Sannazzaro Refinery, following an event occurred in December 2016, and the provision for removal and clean-up (a total amount of €217 million), partially offset by the recognition of third-party insurance compensation (€122 million)

In 2015, the Refining & Marketing and Chemicals segment reported an operating loss of €1,567 million, thereby reducing operating losses by €1,244 million compared to 2014, when this segment reported an operating loss of €2,811 million. The losses reported in 2014 and in 2015 were due to inventory write-down of €1,746 million (pre-tax) in 2014, and of €877 million in 2015, as a consequence of the fall in commodity prices. Both losses included a charge to align the net book value of inventories to their net realizable values at the reporting date, as well as the difference between the current cost of supplies and the one used for IFRS inventory accounting based on the weighted average cost.

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Results in 2015 improved compared to 2014 also for a positive refining scenario. The Eni benchmark for refining margins (Standard Eni Refining Margin – SERM) improved from 3.2 $/BBL to 8.3 $/BBL. Results benefited from initiatives to optimize operations, to reduce costs and to improve energy efficiency.

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 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 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 €583 million, with a reduction of €112 million from 2015. The segment base performance in 2016 was negatively affected by an unfavorable margin scenario, as the Eni benchmark for refining margins, the Standard Eni Refining Margin – SERM was down by 49%, from 8.3 $/BBL in 2015 to 4.2 $/BBL in 2016. Other negative drivers were a planned shutdown of the Livorno refinery for extensive maintenance and the shutdown of EST plant at the Sannazzaro refinery due to the accident occurred at the beginning of December 2016. Moreover, marketing recorded lower results reflecting weaker margins due to stronger competitive pressure and asset disposals in Slovenia and Hungary. These negative trends were counteracted by continuing efficiencies and plant optimization, which drove a reduction in the refining breakeven margin down to $4.2 per barrel. The Chemical business’ results were affected by an unfavorable trading environment, which hit commodity margins.

	Year ended December 31,		
	2014	2015	2016
Refining & Marketing and Chemicals	(€ million)		
GAAP operating profit (loss)	(2,811)	(1,567)	723
(Profit) loss on inventory	1,746	877	(406)
Environmental provisions	138	137	104
Impairment losses	380	1,150	104
Net gains on disposal of assets	43	(8)	(8)
Risk provisions		(5)	28
Provision for redundancy incentives	(4)	8	12
Fair value gains/losses on commodity derivatives	41	68	(3)
Reclassification of currency derivatives and translation effects to management measure of business performance	18	5	3
Other	37	30	26

Total gains and charges	2,399	2,262	(140)
Non-GAAP operating profit (loss)	(412)	695	583

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Corporate and Other activities. These activities are mainly cost centers comprising holdings and treasury, headquarters, central functions like information technology, human resources, self-insurance activities, 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 €681 million in 2016 representing an increase of €184 million from 2015, or 37%, mainly reflecting the recognition of risk provisions related to environmental issues and other that were partly offset by the implementation of cost efficiency measures.

The aggregate Corporate and Other activities reported an operating loss of €497 million in 2015 representing a decrease of €21 million from 2014, or 4.1%, 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:

Net finance expense

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Gain (loss) on derivative financial instruments	165	160	(482)
- Options	68	33	24
- Derivatives on exchange rate	51	96	(494)
- Derivatives on interest rate	46	31	(12)
Exchange differences, net	(415)	(354)	676
Net income from financial activities held for trading	24	3	(21)
Interest income	19	19	15
Finance expense from banks on short and long-term debt	(871)	(838)	(757)
Finance expense due to the passage of time	(293)	(291)	(312)
Other finance income and expense, net	41	(171)	(110)
	(1,330)	(1,472)	(991)
Finance expense capitalized	163	166	106
	(1,167)	(1,306)	(885)

2016 compared to 2015. In 2016, net finance expenses were €885 million, down by €421 million compared to 2015 reflecting the recording of currency gains partly offset by negative fair value adjustments on currency derivatives (for a net positive effect of €440 million), with the latter lacking the formal criteria to be designated as hedges under IFRS. Furthermore, lower finance expense on debt were recorded due to the reduction in net borrowings and to lower interest rates reflecting accommodative monetary policies adopted by the Central Banks worldwide. These positives were partly offset by impairment losses on certain financing receivables granted to equity-accounted entities which are currently executing industrial projects on Eni’s behalf (€121 million). Furthermore, a discount expense of €129 million was recognized relating to certain receivable in the E&P segment owed by certain NOCs due to agreements to repay the overdue amount in instalments with the proceeds associated with mineral initiatives. On that basis, the discount rate utilized reflected also the mineral risk.

2015 compared to 2014. In 2015, net finance expenses were €1,306 million, up by €139 million compared to 2014. The higher gains on derivatives on exchange rate (up €45 million) which did not meet the formal criteria to be designated as hedges under IFRS were more than offset by the negative effect of the impairment of receivables and securities for financing operating activities related to a Nigerian project following the revision of the commodity price scenario. The balance of net expenses was helped by a reduction in the liability relating to the fair-valued options (€33 million) embedded in the convertible bond relating to Snam shares. The reduction reflected the exercise of the option to convert the bond in Snam shares for approximately 6% of the share capital of the investee, with the remaining portion of the bond corresponding to approximately 2% of the share capital closer to maturity.

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f) Net income from investments

2016 compared to 2015. In 2016 the Group reported a net loss from investments of €380 million and mainly related to:

(i)
results of equity-accounted entities (an overall net loss of €326 million), mainly reported by the Exploration & Production segment due to a weaker commodity scenario and the economic difficulties recorded in certain Countries with a negative impact on the level of inflation and exchange rates. Particularly, the segment incurred a loss of €144 million mainly related to our joint ventures in Venezuela (PetroSucre, which book value was completely written off, Cardón IV and PetroBicentenario) driven by changed economics due to the local currency devaluation and rising inflation leading to escalating operating costs.

(ii)
a loss of €144 million was recorded on the equity-accounted interest retained in Saipem. This was driven by the recognition of asset impairment charges and other extraordinary expenses accounted for in Saipem's results due to the impairment review performed by the investee at its CGUs based on its updated industrial plan. That plan, announced in October 2016, factored in a slower recovery in the oil market and in investment plans of the international oil companies;

(iii)
net losses on the divestment of interests (€14 million) mainly relating to the disposal of the residual 2.22% interest in Snam (€32 million), offset by gains on the divestment of interests (€18 million) mainly of the 100% share in Slovenija doo, Eni Hungaria Zrt and other non-core interests;

(iv)
other losses mainly relating to an impairment charge recorded in G&P related to the interest in Unión Fenosa Gas SA (€84 million) due to a reduced profitability outlook and the impairment of receivables in the E&P segment owed by the equity-accounted PetroSucre SA for dividends resolved but yet to be paid (€65 million).

These losses were partly offset by dividends received from entities accounted for at cost (€143 million) relating to Nigeria LNG Ltd (€76 million) and Saudi European Petrochemical Co (€45 million).

2015 compared to 2014. Net income from investments in 2015 was a net gain of €105 million and mainly related to: (i) dividends received from entities accounted for at cost (€402 million), relating to Nigeria LNG Ltd (€222 million) and Snam SpA (€72 million); (ii) gains on disposal of investments (€164 million) which related to a gain recorded on the sale of an 8% interest in Galp (€98 million), gains on the divestment of a 6.03% interest in Snam (€46 million), gains on the divestment of refining infrastructures in Eastern Europe (€70 million), as well as the loss (€47 million) related to the divestment of minor assets in the Gas & Power business in Argentina; and (iii) other net gains including the alignment to stock price at December 31, 2015 of the Snam stock prices pertaining to Eni after the exercise of the conversion right by the bondholders (€49 million calculated on the 2.22% interest owned by Eni at the closing date). Those gains were partly offset by impairment losses registered in the business: (i) E&P relating to Angola LNG Ltd amounting to €469 million, including production and operating costs related to the start-up of liquefaction plant due to the revision of commodity scenario; and (ii) Gas & Power related to the interest on Unión Fenosa Gas SA (€49 million).

These gains are further explained in "Item 18 – note 20 – Investments – of the Notes on Consolidated Financial Statements".

g) Taxes

2016 compared to 2015. In 2016, income taxes amounted to €1,936 million, down by €1,186 million compared to 2015, or 38%. These lower charges mainly reflected lower write-downs of deferred tax assets in connection with improved projections of future taxable profit against which those assets would be utilized compared to 2015. Particularly, in 2015 deferred taxes were written down by €1,740 million relating to foreign subsidiaries of the E&P segment and Italian subsidiaries due to a deteriorated profitability outlook. By contrast, the write-downs of deferred tax assets in 2016 were offset by write-ups. In addition, considering the expected outcome of ongoing negotiations to settle disputed receivables owed by the Nigerian national oil company, the Company utilized a provision for deferred tax liabilities for €380 million as those receivables were considered tax-deductible.

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In 2015 and in 2016, the Group reported tax rate was much higher than the Group historical tax rates. This negative trend was negatively affected by the increased share of taxable profit earned in PSA contracts which bear higher-than-average rates of tax. Furthermore, in many jurisdictions where the Group reported pre-tax losses, the Company was not in the position of recognizing deferred tax assets, due to lack of sufficient future taxable profit against which those tax assets would be utilized. Management is estimating that in the four-year plan 2017-2020 the Group tax rate will progressively normalize in line with an expected recovery in the E&P results in concession contracts and an expected recovery in the pre-tax profit of Italian subsidiaries due to the ongoing upgrading plans at our G&P, R&M and Chemical businesses.

2015 compared to 2014. In 2015, income taxes amounted to €3,122 million, down by €3,344 million compared to 2014, or 51.7%, mainly reflecting lower income taxes currently payable by subsidiaries in the Exploration & Production segment operating outside Italy due to a declining taxable profit. In spite of the fact that in 2015 Eni's group pre-tax earnings were a loss, the Group incurred a net tax expense. This negative development was influenced by a higher tax rate in E&P. The main drivers of this were three. First, the segment's taxable profit was mainly earned in PSA contracts, which, although more resilient in a low-price environment due to the cost recovery mechanism, nonetheless bear higher-than-average rates of tax. Secondly, there was higher incidence of certain non-deductible expenses on the pre-tax profit lowered by the scenario. In addition, the tax rate was impacted by lower recognition of deferred tax assets relating operating losses due to a reduced profitability outlook (€1,058 million). The Group tax rate was also impacted by the write-off of Italian deferred tax assets and other changes of €1,607 million in the full year due to projections of lower future taxable profit at Italian subsidiaries and the reduction of the statutory tax rate from 27.5% to 24%, which was considered as substantially enacted at the reporting date.

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 non-strategic assets. The Group continually monitors the balance between cash flow from operating activities and net expenditures targeting a sound and balanced financing structure.

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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,		
	2014	2015	2016
	(€ million)		
Net profit - continuing operations	1,808	(7,399)	(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	10,898	17,216	7,773
- net gains on disposal of assets	(224)	(577)	(48)
- dividends, interest, taxes and other changes	6,600	3,215	2,229
Changes in working capital related to operations	2,199	4,781	2,112
Dividends received, taxes paid, interest (paid) received during the period	(6,812)	(4,361)	(3,349)
Net cash provided by operating activities - continuing operations	14,469	12,875	7,673
Net cash provided by operating activities - discontinued operations	273	(1,226)	
Net cash provided by operating activities	14,742	11,649	7,673
Capital expenditures - continuing operations	(11,178)	(10,741)	(9,180)
Capital expenditures - discontinued operations	(694)	(561)	
Capital expenditures	(11,872)	(11,302)	(9,180)
Investments and purchases of consolidated subsidiaries and businesses	(408)	(228)	(1,164)
Disposals of consolidated subsidiaries, businesses, tangible and intagible assets and investments	3,684	2,258	1,054
Other cash flow related to investing activity (*) (**)	21	(1,651)	5,736
Changes in short and long-term finance debt	(628)	2,126	(766)
Dividends paid and changes in non-controlling interests and reserves	(4,434)	(3,477)	(2,885)
Effect of changes in consolidation, exchange differences and cash and cash equivalents related to discontinued operations	78	(780)	(3)
Change in cash and cash equivalents for the year	1,183	(1,405)	465
Cash and cash equivalents at the beginning of the year	5,431	6,614	5,209
Cash and cash equivalents at year end	6,614	5,209	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 by investing the proceeds of the disposal plan in the purchase of held-for-trading securities, net cash used in investing activities also

includes 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 No. 9 to the Consolidated Financial Statements. For the definition of net borrowings, see "Financial Condition" below. Cash flows of such investments were as follows:

(€ million)	2014	2015	2016
Investing activity:			
- securities	(19)	(140)	(1,317)
- financing receivables	(519)	(343)	(272)
	(538)	(483)	(1,589)
Disposal:			
- securities	32	1	
- financing receivables	92	182	6,860
	124	183	6,860
Net cash flows used in investing activity	(414)	(300)	5,271

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The table below sets forth the principal components of Eni's change in net borrowings (1) for the periods indicated.

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Net cash provided by operating activities	14,742	11,649	7,673
Capital expenditures	(11,872)	(11,302)	(9,180)
Acquisitions of investments and businesses	(408)	(228)	(1,164)
Disposals	3,684	2,258	1,054
Other cash flow related to capital expenditures, investments and divestments	435	(1,351)	465
Net borrowings(1) of acquired companies	(19)		
Net borrowings(1) of divested companies		83	5,848
Exchange differences on net borrowings and other changes	(850)	(818)	284
Dividends paid and changes in minority interest and reserves	(4,434)	(3,477)	(2,885)
Change in net borrowings(1)	1,278	(3,186)	2,095
Net borrowings(1) at the beginning of the year	14,963	13,685	16,871
Net borrowings(1) at year end	13,685	16,871	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 certain components of Eni's change in net borrowings

In 2016, adjustments to reconcile net profit from continuing operations to net cash provided by operating activities from continuing operations 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 (€7,434 million). Adjustments to net profit also included accrued income taxes (€1,936 million) and interest expense (€645 million), which were more than offset by amounts actually paid (€2,941 million and €780 million, respectively).

In 2015, adjustments to reconcile net profit from continuing operations to net cash provided by operating activities from continuing operations mainly related to non-monetary charges and gains, which primarily regarded depreciation, depletion, amortization, impairment charges (impairment reversals, net) and write-off of tangible and intangible assets (€16,162 million). Adjustments to net profit also included gains on disposals (€577 million) relating mainly to the sale of a number of oil&gas properties in Nigeria, accrued income taxes (€3,122 million) and interest expense (€659 million) more than offset by amounts actually paid (€4,295 million and €692 million, respectively). Cash-outs for income taxes were partly offset by the reimbursement and the disposal to financing institutions of certain tax receivables due to the parent company (approximately €900 million).

a) Changes in working capital related to operations

In 2016, working capital generated an inflow of €2,112 million. This was mainly due to a positive balance between trade receivables collected and trade payables paid (a net inflow of €2,781 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 €1 billion). This inflow was partly offset by utilizations of the risk provision for €1,043 million, part of which related to the settlement of obligations towards third parties mainly in the G&P segment also in relation to the final award of an arbitration procedure involving a long-term gas buyer. Conversely an advance made to the same buyer in the previous reporting period was utilized. Finally the working capital inflow was partly absorbed by a reimbursement in-kind of a financing receivable due by an equity-accounted entity operating a gas field in

Venezuela with trading receivables (€300 million) due by the Venezuelan state-owned oil company (PDVSA). Finally a positive adjustment related the item other current assets and liabilities (up by €647 million) which mainly reflected the impairment of receivables owed by National Oil Companies due to the expected outcome of ongoing negotiations to settle disputed amounts. The G&P segment was the main driver of the cash inflow from working capital in 2016, reflecting also non-recurring trends. We expect that the G&P working capital contribution will normalize going forward.

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In 2015, changes in working capital were positive for €4,781 million as a result of: (i) a positive balance between trade receivables collected and trade payables paid (a net inflow of €2,602 million), which was mainly driven by a positive performance in the Gas & Power segment; (ii) decreasing inventories (a positive €1,638 million) as a result of the alignment of the book value of crude oil and products to market prices (this item being an adjustment of the inventory loss recorded in net profit and as such is not a cash item), as well as reduced inventory levels in R&M due to optimizations measures; and (iii) a positive inflow related to other current assets and liabilities (up by €498 million) which mainly reflected a net positive inflow in the Gas & Power segment due to the collection of pre-paid volumes of gas under take-or-pay contracts and the collection of receivables from supplied long-term customers. These inflows were partly offset by a greater exposure of the E&P segment towards joint venture partners.

b) Investing activities

	Year ended December 31,		
	2014	2015	2016
	(€ million)		
Exploration & Production	10,156	9,980	8,254
Gas & Power	172	154	120
Refining & Marketing and Chemicals	819	628	664
Corporate and other activities	113	64	55
Impact of unrealized intragroup profit elimination	(82)	(85)	87
Capital expenditures - continuing operations	11,178	10,741	9,180
Capital expenditures - discontinued operations	694	561	
Capital expenditures	11,872	11,302	9,180
Acquisitions of investments and businesses	408	228	1,164
	12,280	11,530	10,344
Disposals	(3,684)	(2,258)	(1,054)

Capital expenditures totaled €9,180 million and €11,302 million, respectively in 2016 and in 2015.

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 €1,164 million in 2016 and €228 million in 2015. In 2016, they comprised the subscription of the share capital increase of Saipem (€1,069 million) and minor contribution to equity-accounted entities.

In 2016, disposals amounted to €1,054 million and mainly related to: (i) the divestment of the 12.503% interest in Saipem SpA to CDP Equity SpA in January 2016 (€463 million), an interest in Snam due to exercise of the conversion right by bondholders (€332 million) as well as fuel distribution activities in Eastern Europe.

In 2015, disposals amounted to €2,258 million and mainly related to: (i) the divestment of an available-for-sale interest in Snam due to exercise of the conversion right by bondholders (€911 million); (ii) an available-for-sale interest in Galp Energia (€658 million) in order to reimburse an out-of-the-money convertible bond which was due in 2015; and (iii) the divestment of non-strategic assets in the Exploration & Production and in the R&M businesses.

In 2016, other cash flow related to investing activities were positive for €465 million and included the reimbursement in-kind of a financing receivable owed by our equity-accounted entity Cardon IV for €300 million. Cardon IV reimbursed Eni with a trade receivable due by the Venezuelan State-owned oil company (PDVSA) on the supplies of gas volume produced at the Perla project. Furthermore, the production restart of the Kashagan field and the achievement of a production milestone in the fourth quarter of 2016 triggered the reimbursement of the first instalment of a receivable of the divestment of an interest of 1.71% of the project to the Kazakh national oil company occurred in 2008, with a cash-in of €152 million.

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c) Dividends paid and changes in non-controlling interests and reserves

In 2016, dividends paid and changes in non-controlling interests and reserves (€2,885 million) related almost exclusively to cash dividends to Eni shareholders (€2,881 million, of which €1,441 million relating to the 2016 interim dividend and €1,440 million to the final dividend for fiscal year 2015.

In 2015, dividends paid and changes in non-controlling interests and reserves (€3,477 million) mainly related to: (i) cash dividends to Eni shareholders (€3,457 million, of which €1,440 million relating to 2015 interim dividend and €2,017 million to the balance dividend for fiscal year 2014); and (ii) the distribution of dividends to non-controlling interests by other consolidated subsidiaries (€21 million).

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, non-operating financing receivables and securities not related to operations. 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 €6,404 million as of end of 2016 and were accounted as mark-to-market financial instruments. For further information see "Item 18 – note 9 – 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.

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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,					
	2015			2016		
	Short-term	Long-term	Total	Short-term	Long-term	Total
	(€ million)					
Finance debt (short-term and long-term debt)	8,396	19,397	27,793	6,675	20,564	27,239
Cash and cash equivalents	(5,209)		(5,209)	(5,674)		(5,674)
Securities held for trading and other securities held for non operating purposes	(5,028)		(5,028)	(6,404)		(6,404)
Non operating financing receivables	(685)		(685)	(385)		(385)
Net borrowings	(2,526)	19,397	16,871	(5,788)	20,564	14,776

		As of December 31,	
		2015	2016
Shareholders' equity including non-controlling interest as per Eni's Consolidated Financial Statements prepared in accordance with IFRS	(€ million)	57,409	53,086
Ratio of finance debt to total shareholders' equity including non-controlling interest		0.48	0.51
Less: ratio of cash, cash equivalents and certain liquid investments not related to operations to total shareholders' equity including non-controlling interest		(0.19)	(0.23)
Ratio of net borrowing to total shareholders' equity including non-controlling interest (leverage)		0.29	0.28

In 2016, net borrowings amounted to €14,776 million, representing a €2,095 million decrease from 2015. This reduction was driven by repayment of debt due to the net cash flows provided by operating activities of continuing operations (€7,673 million) and the closing of the Saipem transaction, which entailed net proceeds of €5.2 billion. These latter comprised the reimbursement of financing receivables due to Eni by the former subsidiary (€5,818 million), the proceeds of the disposal of a 12.503% interest in the entity (€463 million), net of the cash-out to subscribe pro-quota Saipem'share capital increase (€1,069 million). Other divestment for the year amounted to €0.6 billion and mainly related to an interest in Snam due to exercise of the conversion right by bondholders (€332 million) as well as fuel distribution activities in Eastern Europe.

These inflows funded cash outflows relating to capital expenditures totaling €9,180 million and dividend payment to Eni shareholders amounting to €2,881 million, with the surplus used to pay down finance debt.

Furthermore, the change in the Group net borrowing y-o-y was influenced by the reclassification of financial assets held by the Group captive insurance company as non operating assets, which have been netted against finance debt in determining the Group net borrowings (with a positive effect of €0.6 billion). In previous reporting periods, those financial assets were committed to fund the loss provision and as such were part of capital employed. The change in classification reflects new regulatory requirements applicable to the exercise of the insurance activity from January 1, 2016, based on the provisions of EU Solvency II Directive (the so-called Minimum Capital Requirement – MCR – and Solvency Capital Requirement – SCR). The new rules require that insurance companies meet certain capital and solvency ratios as minimum requirements to continue performing the insurance activity. Therefore, it is no longer necessary to commit the financial assets of the insurance company to funding the loss provisions. Accordingly, those assets, which mainly comprise available-for-sale securities and bank deposits, have ceased to be classified as held for operating purposes.

The ratio of finance debt to total equity was 0.51 at 2016 year-end.

The Group Non-GAAP measure of its financial condition “Leverage” was 0.28 at December 31, 2016 reporting a decrease from 0.29 as of the end of 2015. This decline was driven by lower net borrowing, the effects of which were partly offset by a reduction in the Group total equity as explained below.

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Total equity decreased by €4,323 million from December 31, 2015. This was due to the net loss (€1,457 million), the derecognition of Saipem non-controlling interest (€1,872 million), as well as dividend distribution of €2,885 million (including the 2015 balance and the 2016 interim dividends paid to Eni's shareholders amounting to €2,881 million). These effects were partially offset by a positive change in the cash flow hedge reserve (€883 million) and positive foreign currency translation differences (€1,198 million) due to the 3.2% depreciation of the euro against the US dollar at year end (down by 3.2% due to the exchange rate recorded on December 31, 2016 at 1.054 euro, compared to 1 euro = 1.089 US$ at December 31, 2015).

Total debt of €27,239 million consisted of €6,675 million of short-term debt (including the portion of long-term debt due within twelve months equal to €3,279 million) and €20,564 million of long-term debt.

Total debt included unsecured bonds for €19,003 million (including accrued interest and discount on issuance). Bonds maturing in the next 18 months amounted to €3,724 million (including accrued interest and discount). Bonds issued in 2016 amounted to €2,984 million (including accrued interest and discount). Total debt was denominated in the following currencies: euro (90%), U.S. dollar (7%), British pound (2%) and 1% in other currencies.

Capital expenditures by segment

Exploration & Production. In 2016, capital expenditures of the Exploration & Production segment amounted to €8,254 million, mainly related to the development of oil&gas reserves (€7,770 million). Significant expenditures were directed mainly outside Italy, in particular in Egypt, Angola, Kazakhstan, Indonesia, Iraq, Ghana and Norway. Development expenditures in Italy also comprised the upgrading of certain plants at the Viggiano oil center in Val d'Agri, which did not alter the plant set up. This upgrading addressed certain objections made by jurisdictional Authorities about the proper function of the plants and were duly authorized by the competent department of the Italian Ministry of Economic Development. Due to this upgrading, plant activities were regularly restarted following notification by the public prosecutor that it has definitively repealed the plant seizure. (see – Item 4 – Exploration & production segment – Italy) as well as sidetrack and workover activities in mature fields. Exploration expenditures (€417 million) were directed in particular in Egypt, Indonesia, Libya and Angola.

In 2015, capital expenditures of the Exploration & Production segment amounted to €9,980 million, mainly related to the development of oil&gas reserves (€9,341 million). Significant expenditures were directed mainly outside Italy, in particular Angola, Norway, Egypt, Kazakhstan, Congo, Indonesia and the United States. Development expenditures in Italy concerned the well drilling program and facility upgrading in Val d'Agri, as well as sidetrack and infilling activities in mature fields. Exploration expenditures amounting to €566 million were directed outside Italy, in particular in Egypt, Libya, Cyprus, Gabon, Congo, the United States, the United Kingdom and Indonesia.

Gas & Power. In 2016, capital expenditures in the Gas & Power segment totaled €120 million and mainly related to initiatives to improve flexibility of the combined-cycle power plants (€41 million) and to develop the gas marketing activity (€69 million).

In 2015, capital expenditures in the Gas & Power segment totaled €154 million and mainly related to initiatives to improve flexibility of the combined-cycle power plants (€69 million) and to develop the gas marketing activity (€69 million).

Refining & Marketing and Chemicals. In 2016, capital expenditures in the Refining & Marketing and Chemicals segment amounted to €664 million and regarded mainly: (i) refining activities in Italy and outside Italy (€298 million) aiming fundamentally at plants improving, 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 (€123 million); (iii) upgrading and maintenance at petrochemical plants (€200 million).

In 2015, capital expenditures in the Refining & Marketing and Chemicals segment amounted to €628 million and regarded mainly: (i) refining activities in Italy and outside Italy (€282 million) aiming fundamentally at plants improving, as well as initiatives in the field of health, security and environment; (ii) upgrading and rebranding of the refined product retail network in Italy (€75 million) and in the Rest of Europe (€51 million); (iii) upgrading and maintenance at petrochemical plants (€177 million).

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Recent developments

The table below sets forth certain indicators of the trading environment for the periods indicated:

	Three months ended December 31 2016	Three months ended March 31, 2016	January 1 through March 17, 2017
Average price of Brent dated crude oil in U.S. dollars(1)	49.46	33.89	54.66
Average EUR/USD exchange rate(2)	1.078	1.102	1.063
Standard Eni Refining Margin (SERM)(3)	4.7	4.2	4.2

(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 17, 2017 the Brent crude oil price was 54.66$/BBL on average, 61% higher than in the first quarter of 2016 and 10% higher than in the fourth quarter 2016. This trend will positively affect reported revenues, profitability and cash flow of our Exploration & Production segment.

Significant transactions

On March 9, 2017, Eni and ExxonMobil signed sale and purchase agreement whereby ExxonMobil is going to acquire a 25% indirect interest in the Area 4 block, offshore Mozambique. Eni currently holds a 50% indirect interest in the block through a 71.4% stake in Eni East Africa, which is operator of the Area 4 concession with a 70% interest. The agreed terms include a cash price of approximately $2.8 billion. The acquisition will be completed subject to satisfaction of certain conditions precedent, including clearance from Mozambican and other regulatory authorities. Eni will continue to lead the Coral Floating LNG project and all upstream operations in Area 4, while ExxonMobil will lead the construction and operation of natural gas liquefaction facilities onshore. This operating model will enable the use of best practices and skills within Eni and ExxonMobil with each company focusing on distinct and clearly defined scopes while preserving the benefits of a fully integrated project.

The Company's Annual General Shareholders Meeting scheduled on April 13, 2017, has been convened to approve the full year dividend proposal of €0.80 per share of which 0.4 paid as interim dividend in September 2016. Eni expects to pay the balance of the dividend for fiscal year 2016 amounting to €0.40 per share in April 2017. The total cash out is estimated at approximately €1.4 billion.

Management's expectations of operations

Exploration & Production

Management intends to boost the cash generation in the E&P segment leveraging on profitable production growth, capital discipline and strict control of operating expenses and project execution. Exploration activities will continue to be key to the Company's growth prospects in the short and long-term. The Company is leveraging on its dual exploration model, which envisages both the rapid development of the discovered resources and the divestment of stakes of our exploration discoveries in order to accelerate the conversion of our resources into cash. The effectiveness of our dual exploration model has been proven by the divestment of a 40% interest in the Zohr gas discovery off

Egypt, with a value to Eni of approximately €2 billion including the reimbursement of the capital expenditure incurred in 2016 to develop the prospect, as well as by the preliminary agreement signed for the divestment of a 25% interest in Area 4, offshore Mozambique with an expected cash consideration of approximately $2.8 billion.

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We expect to increase our hydrocarbons production at an average rate of 3% across the 2017-2020 plan period. This growth target factors in the effects associated with our planned disposals. For 2017, we expect a production growth of approximately 5%. This grow will be fuelled organically by new fields start-ups, full production at the Goliat and Kashagan projects and the ramp-up of the other fields started in 2016, the recovery of the full plateau at the Val d'Agri profit center and continuing production optimization to fight fields natural decline. The main start-ups of 2017 include the Zohr gas field off Egypt expected at year-end, the oil&gas project of Offshore Cape Three Points in Ghana, the East Hub of Block 15/06 off Angola and the Jangkrik gas project in Indonesia. The East Hub project has already achieved first oil in February 2017. In subsequent years, we are planning new project start-ups in Egypt, Angola, Algeria and Norway. New field start-ups, production ramp-ups and continuing production optimization will add approximately 850 KBOE/d in 2020. We believe that those production targets have good visibility because they related to already-sanctioned projects, mostly of which are operated.

Our production plans includes assumptions relating to production levels in Libya and Nigeria, which are exposed to risks of disruptions and political instability. In 2016, Libya represented approximately 20% of the Group total hydrocarbons productions for the year and going forward the contribution of Libya to our future production levels albeit slowing down will remain significant. To factor in possible risks of unfavorable geopolitical developments mainly in Libya but also elsewhere in other countries of Eni presence, 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.

Our production plans are incorporating our Brent price scenario of 55 $/BBL in 2017 and a gradual recovery in the subsequent years up to our long-term case of 70 $/BBL in 2020 and going forwards (on constant monetary term compared to 2020, i.e. from 2020 onwards crude oil prices will grow in line with a projected inflationary rate). See "Item 4 – Exploration & Production". Our recovery assumptions are based on the progressive rebalancing of global oil markets, which will be supported by the OPEC agreement reached in November 2016 to cut the cartel output joined also by non-Opec members and the effects of the curtailment in expenditures made by international oil companies during the downturn. However, there are some risks to this outlook, including effective compliance of OPEC member countries with the planned production quotas and the pace at which unconventional oil producers in the US will be able to bring production back to markets, leveraging the short-cycle nature of this business and rising productivity. Oil price assumptions are particularly significant when it comes to assessing the Company's future production performance considering the entitlement mechanism under Eni's PSAs and similar contractual schemes. In 2016, the Company estimated that production entitlements in its portfolio of PSAs increased by approximately 20 KBOE/ d, or 1,900 BBL/d for each $1 change in oil prices compared to 2015. We note that in case oil prices differ significantly from our own forecasts, the result of the above mentioned sensitivity of production to oil price changes may be significantly different.

Due to those risks and uncertainties, management intends to retain a strong focus on capital discipline, project execution and cost control. First, our capital budget in the E&P segment for the four-year plan 2017-2020 is estimated 13% lower than the previous capital plan 2016-2019 (in each cases net of the capex associated with planned disposals). In spite of an expected reduction in capital spending, our growth targets in 2017-2020 are above our previous planning assumptions relating the period 2016-2019 due to our phased approach in developing our production projects. This approach will enable the Company to reduce financial exposure and to accelerate production start-ups. Secondly, we intended to be more selective on investment options. Thirdly, we plan to seek opportunities for further reductions in our development and operating costs by renegotiating contracts for the supply of upstream plants, equipment and other infrastructures as well as the supply of oilfield services and drilling rates considering the uncertainties surrounding a recovery in expenditures by oil companies.

Finally, management will focus on delivering the planned projects on time and on budget. Some 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. Furthermore, in the past we experienced delays and cost overruns at certain projects, which were caused by

poor execution by our EPC contractors. We plan to mitigate those risks in the future by continuing deployment of our capabilities and by means of: (i) in-sourcing critical engineering and project management activities; (ii) increasing direct control and governance on construction activities; (iii) deploying our employees and competences to manage hook-up and commissioning; and (iv) entering into framework agreements with major suppliers, using standardized specifications to speed up pre-award process for critical equipment and plants and increasing focus on supply chain programming to optimize order flows. Effective project execution has been boosted in recent years by our changed approach in exploration activities, which have been redirected towards mature and low-complexity areas where we can achieve fast time-to-market and cost synergies. Furthermore, phased project development and strict integration between exploration and development have improved the overall project execution and cost efficiency. 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.

Management also plans to increase the share of operated production in the Company's portfolio. We expect to operate more than 74% of the plan period production. Project operatorship enables the Company to better schedule and control project execution, expenditures and timely achievement of project milestones and to mitigate the operational risk associated with drilling activities at high pressure-high temperature wells and at deep waters well by deploying our technologies and competences. Eni estimates that these wells will represent approximately 13.5% of the planned wells to be drilled in 2017.

In the next four years, our exploration activities will focus on supporting the replacement of produced reserves and on contributing to cash generation. Our exploration investment will be mainly directed to:

i) Appraisal of the recent discoveries and near-field plays, where in case of success we can leverage on existing infrastructures in order to readily put into production the discovered resources;

ii) Initiatives in new areas in proximity to end markets, targeting conventional prospects with high interests in order to implement our dual exploration model in case of material discoveries.

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.

We project a flat trend in gas demand in Europe and in Italy over the next four-year plan. Demand growth will be dampened by sluggish economic growth, rising competition from renewables and increasing energy efficiency. On the supply side, the growing importance of liquid hubs and large availability of LNG will drive continuing competition and pricing pressure. Going forward LNG supplies will be fueled by the coming on stream of several export terminals in the United States which will monetize the country's large reserves of shale gas and the start-up of important LNG projects in the Pacific area. 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.

Against this scenario, the Company priority in its Gas & Power business is to achieve structural profitability and retain positive cash generation. Our strategy in the Gas & Power sector will leverage on the renegotiations of our long-term gas supply contracts in order to align pricing and volume terms to current market conditions and dynamics, optimization of logistic costs, the development of our portfolio of highly profitable businesses and cost efficiencies and operational streamlining.

Our take-or-pay, long-term supply contracts include revisions clauses whereby each counterpart has right to renegotiate the economic terms and other conditions periodically, in relation to ongoing changes in the gas scenario. Leveraging on recent renegotiations, 90% of our portfolio of supply contracts is currently indexed to HUB prices and will benefit the 2017 performance. Looking forward, we expect to fully align our supply portfolio to market conditions and dynamics in terms of both pricing and volumes. Our renegotiation efforts will seek to obtain cost indexation that will track our pricing formulas, to align our procurement costs to prices prevailing in the wholesale

market, which includes sales to large industrial and
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power companies and resellers, and to match our minimum contractual take with the dimension of our addressable market. The renegotiation strategy is subject to the constraints dictated by availability of the contractual windows. Management believes that the outcome of those renegotiations is uncertain in respect of both the amount of the economic benefits that will ultimately be achieved and the timing of recognition in profit. In case Eni and the gas suppliers fail to agree on revised contractual terms, an arbitration procedure could be commenced to solve the commercial dispute. Furthermore, Eni's suppliers may file a counterclaim to dismiss Eni's request for a price review or renewed contractual terms. These possible developments increase the risks and uncertainties relating the outcome of those renegotiations. Therefore, future results of the gas marketing activities are subject to increasing volatility and unpredictability. The expected termination of certain long-term gas supply contracts with take-or-pay clause will reduce Eni's contractual minimum take and will add flexibility to Eni's portfolio and renegotiation strategy. Furthermore, we plan to almost complete the recovery of our pre-paid gas volumes due to the triggering of the take-or-pay clause in past reporting periods. This asset amounted to €0.3 billion at 2016 year-end. We expect to improve profitability in gas marketing through initiatives intended to reduce logistic costs by reselling unutilized transport capacity to other operators and by possibly benefitting from expected liberalization measures in the European gas system designated to increase the liquidity of spot markets.

The Company intends to grow its presence in market segments where margins can be sustained in the long-term. As part of this plan, we intend to strengthen our role as a global player in LNG trading where we plan to achieve steady profitability, also leveraging on integration with our upstream operations by marketing equity gas. We will seek to preserve margins on sales to large accounts by leveraging on the Company's multiple presence across various markets and expertise in delivering innovative and tailor-made offering structures to best suit customers' needs by providing complex pricing formulas, hedging against the commodity risk and flexibility in volumes collection. In the retail segment, our priority is to maximize profitability and cash generation through more effective and efficient operations. We will closely monitor the level of working capital and we will be more selective in new customer additions in order to reduce the portfolio risk and counterparty losses. We intend to increase the weight in our portfolio of customers who are willing to sign supply contracts in the open market rather than opting to use the regulated tariffs established by Italian gas authorities. The Company's marketing effort will address retail customers in Italy and in the main European markets in order to valorize the existing customer base against the backdrop of escalating competitive pressures. This will be achieved by the offer of new products and services, brand identity, the administrative advantages of the dual offer of gas and electricity, a competitive cost to serve and continuing innovation in processes, promotion and customer care and post-sale assistance. We believe that offering a wide range of valuable services with the selling of the commodity will underpin the profitability of our retail operations considering that the regulatory modifications to the indexation of the raw material cost have substantially flatten the margin on the commodity. Management will also seek to improve profitability by means of cost efficiencies particularly by streamlining business support activities and reducing general and administrative costs.

Finally, the Company intends to capture margins improvements by means of trading activities by entering into derivative contracts both in the commodity and the financial trading venues in order to capture possible favorable trends in market prices, within the limits set by internal policies and guidelines that define the maximum tolerable level of market risk. As part of this strategy, the Company intends to improve results of operations by effectively managing the flexibilities associated with the Company's assets (gas supply contracts, transportation rights, storage capacities, unutilized power capacity). This can be achieved through strategies of asset-backed trading by entering into derivative contracts to leverage on commodity price volatility, the risks of which might be absorbed in part or entirely by the natural hedge granted by the asset availability. Asset-backed activities may lead to gains, as well as losses the amount of which could be significant. For further information on the market risk and how the Company manages it see "Item 11 – Quantitative and Qualitative Disclosures about Market Risk".

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 benefits of ongoing 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.

These projections could be subject particularly to the risks of further contraction in demand or the total addressable market and the risks related to the outcome of contract renegotiations. For more information see the specific risk paragraph in "Item 3 – Risk factors".

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Refining & Marketing

The outlook of the European refining sector is unfavorable due to structural headwinds in the industry pressured by overcapacity, stagnant fuel demand, energy efficiency and rising competition from cheaper products streams from the Middle East and other areas. Management expects refining margins in 2017 and going forward to remain around the weak levels registered in 2016 at about 4$ per barrel, where the Company's refining business is at breakeven. At the end of the plan period it is projected an improvement in refining margins due to the enactment of a new regulation regarding the quality of fuel used in the bunker segment.

Against this backdrop, the Company priority is to retain profitable and cash-positive operations even in a depressed downstream oil environment, by further reducing the breakeven margin of Eni refineries. The refining business has undergone a restructuring process resulting in a reduction of the installed capacity by more than 30% versus the 2012 baseline. This process has comprised the conversion of the Venice refinery into a green refinery for the production of bio-fuels based on a proprietary technology, the shutdown of Gela refinery, which is undergoing a transformation into a green refinery like the Venice site, asset disposals, the shutdown of unprofitable lines and other efficiency initiatives. We believe that additional optimization is needed considering the structural headwinds and volatility of the refining scenario. Our goal is to lower the breakeven margin to 3$ per barrel by 2018. The planned initiatives include the completion of the Gela project and the second phase of Venice upgrading, optimization of plant setup and continued efficiency gains in logistics, energy management and capital discipline. In Marketing activities, where we expect competitive pressure to continue due to weak demand trends, we are planning to achieve a gradual improvement in results of operations mainly by focusing on innovation of products and services anticipating customer needs, as well as efficiency in the marketing and distribution activities.

Retail operations abroad will be focused on the core markets of Germany, Austria, Switzerland and France, where we intend to exploit synergies with Italian operations, brand awareness, a fair market share and development of non-oil activities to retain steadily profitable operations. We have completed the refocusing program of our portfolio of activities exiting Eastern Europe.

Overall, we expect that under constant 2017 scenario assumptions, in the next four-year plan the business will generate enough cash to fund its capital expenditure plans and to generate a surplus.

Chemical

The outlook in the chemical business is unfavorable due to structural headwinds in the industry pressured by overcapacity, weak macroeconomic growth and rising competition from cheaper products streams from the Middle East, Far East and the US. In addition, our petrochemical commodities are exposed to the volatility of the crude oil-based feedstock costs. Like the R&M business, our chemical activity has undergone a deep restructuring process. Over the last few years, we have lowered the cost base and exposure to commodity risk 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, including self-financing the business capital requirements. The industrial plan contemplates the completion of the restructuring process at unprofitable sites, increased plant flexibility and optimization, development of new products and specialties as well as the start-up of certain joint ventures in East Asia with local partners to produce and market elastomers.

Overall, we expect that even under our conservative scenario assumptions the business will generate enough cash to cover its capital expenditures requirements along the plan period.

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Capital expenditure plans

Over the next four years, the Company plans to invest €31.6 billion, excluding capex associated with the disposal plan, to support continued organic growth in oil&gas production; approximately 86% of planned capital expenditures is expected to be directed to the Exploration & Production segment. Eni's capital expenditure program is reflective of a lower oil price environment and of uncertainties about future trends in the oil markets. Our capital expenditure plan will be more selective than in the past and will focus on the more profitable projects in portfolio and on project re-phasing and modularization. These optimizations and curtailments, as well as wider portfolio effects are expected to drive an 8% reduction in capital expenditure compared to the previous plan at constant exchange rates and net of capital expenditures associated with our disposal activity, without sacrificing our production growth targets. E&P capital expenditure for the four-year plan is expected to decrease by 13% compared to the previous plan. In 2017 we expect overall capex in the range of €7.6 billion, down by 18% vs 2016 at a constant exchange rates and post portfolio transactions.

Development of oil&gas reserves will attract some €25 billion. Project start-ups and plateau enhancement at existing fields will be geographically diversified and executed mainly in Egypt, with the development of the very important Zohr gas discovery, Mozambique, Italy, Iraq, Kazakhstan, Nigeria, Norway, Libya, Angola and Ghana. Egypt will attract approximately 20% of the Group capital expenditure over the plan period.

Exploration capex will amount to €2.1 billion. Our projects will include appraisal of recent discoveries and near-field activities designed to provide fast production support and contribution to the cash flow, 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.

We are planning to invest approximately €2.2 billion in R&M which will mainly be directed to the completion of the Gela reconfiguration project, the repair of the EST unit at the Sannazzaro site and various initiatives of plant upgrading, as well as network upgrading. The Chemical business will attract approximately €1 billion for plant upgrading and selected growth initiatives. In G&P we intend to spend approximately €0.5 billion. Finally, we will invest approximately €0.5 billion to develop photovoltaic and other renewable-related power plants in our industrial properties in Italy or in countries where we are conducting E&P operations.

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 2021 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 2016, management assessed that the cost of capital to the Group was marginally lower than in 2015 mainly due to a reduced premium for the sovereign risk incorporated into the yields on Italian ten-year bonds, partly offset by an increased volatility of the Eni share and an appreciation of the country risk. This latter factors in the perceived level of risk associated with each country of operations in terms of current trends and conditions in the macroeconomic, business, regulatory and socio-political framework, as well as the consensus outlook. In 2016, our average premium for the country risk was higher than in 2015 due to a deteriorated political and financial outlook of certain countries where we are conducting upstream operations. A country risk premium is added to the Group WACC 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 the uncertainties about future trends in market fundamentals and price volatility, management's priorities remain to maximize cash generation and to preserve a solid balance sheet. We believe the initiatives implemented by management during the downturn intended to lower the cost base, to optimize investments and to streamline operations together with recent exploration success have improved the Company's competitive position. Currently we are estimating that on average the Company will be able to fund its requirements for capital expenditures with cash flow from operations in a Brent price environment lower than 45 $/BBL on average in the next four-year plan. We have also evaluated our financial resiliency considering our commitment to pay a floor dividend of €0.8 per share equating to approximately €2.9 billion per year. We estimate that in the 2017-2020 plan the Company will be able to fund through cash flow from operations both the planned capital expenditures and the floor dividend at 60 $/BBL in 2017 and at a Brent price lower than 60 $/BBL going forward. These targets are reflective of the Company's initiatives in lowering its cost base and in optimizing its capital plan without impairing its ability to pursue its growth objectives.

During the plan period, management expects to execute an asset disposal program in the range of €5-7 billion, which will comprise the dilution of interests in our exploration assets, non-strategic hydrocarbons producing assets and other marginal assets in the mid and downstream businesses. These expected cash inflows will improve the Group's financial flexibility. These planned disposals exclude the already defined divestment of a 40% interest in the Zohr gas discovery, off Egypt, while they include the disposition of an interest in our exploration asset in Mozambique.

During the downturn, in spite of the sharp contraction in the operating cash flow due to lower oil prices, the Company has managed to maintain its key ratio of net borrowings to equity – leverage – within the ceiling of 0.3 through a combination of cost cuts, asset disposals, capital expenditure curtailments and working capital optimization. At the end of 2016, our leverage stood at 0.28. Management believes that the target ceiling leverage is consistent with the Company's business profile, which features an increasing exposure to the Exploration & Production segment. In 2017, we expect that the Company leverage will improve from 2016. This will be driven by the planned portfolio transactions, including the likely completion of the Zohr divestment, and an expected reduction of 18% in the Group capital expenditure at constant exchange rates versus 2016, post portfolio transactions. This forecast is also based on the Company's projected levels of Brent prices at which cash flow from operations is expected to fund the planned capital expenditure for the year.

Our cash flow projections 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 net profit and cash flow from operations vary by approximately €0.2 billion for each dollar change in Brent prices on a yearly basis compared to our price forecast. We note that the Brent price in the period January 1 to March 17, 2017 was approximately 55 $/BBL on average (it was 34 $/BBL on average in the period January 1 to March 31, 2016). 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. Particularly, approximately 37% of the planned investment in the four-year plan 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 1.08-1.20 U.S. dollars per euro in the 2017-2020 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, as well as a potential positive driver of the Group results of operations, cash flow and balance sheet in case the U.S. dollar appreciates against the euro. We note that in the period January 1 to March 17, 2017 the EUR/USD exchange rate was approximately 1.06 and appreciated year-on-year. This trend will favorably affect the reported amounts of operating profit and operating cash flow in our Exploration & Production segment. However, the net impact of the U.S. dollar appreciation on the Group liquidity and net borrowings is uncertain as our capital expenditures are mainly denominated in U.S. dollars. See "Item 3 – Risk factors".

Dividend policy

Considering the weak oil price environment, in 2015 the Company decided to rebase the annual dividend at €0.80 per share, which is our floor dividend. This floor dividend has been confirmed for fiscal year 2016.

In 2017, we confirm our plan to pay a cash dividend of €0.80 per share. Going forward, we remain committed to a progressive distribution policy in line with our plans of underlying earnings and cash flow growth and the scenario evolution. This forecast is dependent on the results that ultimately will be achieved in implementing our strategy and on management's estimations of the minimum level of Brent prices at which the Company's cash flows from operating activities are able to fund planned capital expenditures and dividend payments. This projected level of cash neutrality is dependent upon achievement of our plans of profitable production growth and upgrading of profitability in mid and downstream businesses.

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 38 – 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 38 – Guarantees, commitments and risks – of the Notes on Consolidated Financial Statements".

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Contractual obligations

The amounts in the table refer to expected payments, undiscounted, by period under existing contractual obligations commitments.

	Total	2017	2018	2019	2020	2021	2022 and thereafter
Total debt	29,318	8,492	2,126	4,120	2,914	1,331	10,335
Long-term finance debt	23,653	2,988	2,090	4,044	2,914	1,285	10,332
Short-term finance debt	3,396	3,396					
Fair value of derivative instruments	2,269	2,108	36	76		46	3
Interest on finance debt	4,007	696	557	486	386	277	1,605
Guarantees to banks	84	84					
Non-cancelable operating lease obligations(1)	2,418	593	353	257	231	199	785
Decommissioning liabilities(2)	16,281	253	580	417	400	184	14,447
Environmental liabilities	2,689	281	249	255	202	71	1,631
Purchase obligations(3)	120,225	10,891	9,265	9,511	8,839	7,961	73,758
Natural gas to be purchased in connection with take-or-pay contracts(4)	110,697	8,429	7,912	8,277	7,916	7,312	70,851
Natural gas to be transported in connection with ship-or-pay contracts(4)	6,620	1,569	1,053	943	724	478	1,853
Other take-or-pay and ship-or-pay obligations	724	114	105	101	96	80	228
Other purchase obligations(5)	2,184	779	195	190	103	91	826
Other obligations(6)	129	9	3	2	2	2	111
of which:							
- Memorandum of intent relating to Val d'Agri	129	9	3	2	2	2	111
TOTAL	175,151	21,299	13,133	15,048	12,974	10,025	102,672

(1)
Operating leases primarily regarded assets for drilling activities, time charter and long-term rentals of vessels, lands, service stations and office buildings. Such leases did not include renewal options. 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 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)
Mainly refers to arrangements to purchase capacity entitlements at certain re-gasification facilities in the United States of euro 1,226 milion.

(6)
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 31 to the Consolidated Financial Statements).

The table below summarizes Eni's capital expenditure commitments for property, plant and equipment as of December 31, 2016. 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	2017	2018	2019	2020	2021 and subsequent years
	(€ million)					
Committed projects	23,756	6,733	6,679	4,218	2,441	3,685

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
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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 38 of the Notes on Consolidated Financial Statements".

As of December 31, 2016, Eni maintained short-term unused borrowing facilities of €12,308 million, of which €41 million committed. Long-term committed borrowing facilities amounted to €6,236 million, of which €700 million were due within 12 months. These facilities bore interest rates and fees for unused facilities that reflected prevailing market conditions. Eni has in place a program for the issuance of Euro Medium Term Notes up to €20 billion, of which about €16.3 billion were drawn as of December 31, 2016.

Working capital

Management believes that, taking into account unutilized credit facilities, Eni's 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 38 of the Notes on Consolidated Financial Statements".

For information about credit losses in 2016 and the allowance for doubtful accounts see "Item 18 – note 10 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 38 of the Notes on Consolidated Financial Statements".

Research and development

For a description of Eni's research and development operations in 2016, see "Item 4 – Research and development".

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Item 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

Directors and Senior Management

The following table lists the Company's Board of Directors as at March 2017:

Name	Position	Year elected or appointed	Age
Emma Marcegaglia	Chairman	2014	51
Claudio Descalzi	CEO	2014	62
Andrea Gemma	Director	2014	43
Pietro A. Guindani	Director	2014	59
Karina A. Litvack	Director	2014	54
Alessandro Lorenzi	Director	2011	68
Diva Moriani	Director	2014	48
Fabrizio Pagani	Director	2014	50
Alessandro Profumo1	Director	20152	60

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 May 8, 20143 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, 2016.
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 Luigi Zingales4 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 May 9, 2014, the Board appointed Claudio Descalzi as the Chief Executive Officer of the Company.
The provisions designed to ensure gender balance were applied for the first time in the aforementioned elections. Three Directors out of nine, including the Chairman, were drawn from the less represented gender, thereby already reaching the ratio of one-third of the Directors, instead of the ratio of one-fifth as provided by the law for the first relevant election of the Board. The ratio of one-third of the Directors belonging to the less represented gender shall also apply to the next two subsequent terms of the Board of Directors.
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 Businesseurope and of the Luiss Guido Carli University, 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

(1)
On July 29, 2015, the Board of Directors of Eni co-opted Alessandro Profumo as Director replacing Luigi Zingales, who resigned from the Board on July 2, 2015. The Director Profumo was confirmed by the Shareholders' Meeting on May 12, 2016.

(2)
Alessandro Profumo was Director of Eni from May 2011 to May 2014.

(3)
On July 29, 2015, the Board of Directors of Eni co-opted Alessandro Profumo as Director replacing Luigi Zingales, who resigned from the Board on July 2, 2015. The Director Profumo was confirmed by the Shareholders' Meeting on May 12, 2016.

(4)
Luigi Zingales resigned from the Board on July 2, 2015.

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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. 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 with a degree in business administration from the Bocconi University in Milan and attended a Master's 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 for 2016/2017. 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 Eni's Exploration & Production Division. From 2006 to 2014 he was President of Assomineraria and from 2008 to 2014 he was Chief Operating Officer of Eni's Exploration & Production Division. 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" 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". He graduated with a degree 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, Law Department, Member of the Strategic Board of the American University of Rome and Appeal Court Lawyer and Partner in the Law and Tax Firm Gemma & Partners. He is a Member of the Studies Centre of the Chamber of Arbitration of Rome. He is Deputy Chairman of Serenissima SGR SpA and Chairman of the Watch Structure in Sorgente SpA. He is a member of the Board of Directors of Banca UBAE SpA and of Global Capital PLC. He is President of Board of Statutory Auditors of PS Reti S.p.A. and Sirti S.p.A. He is a member of the Board of Directors of Cinecittà Centro Commerciale S.r.l. He is also Official Receiver of Valtur SpA, Liquidator of Novit Assicurazioni SpA, Sequoia Partecipazioni SpA, Corit SpA and of Sigrec SpA (Unicredit Group).

Pietro A. Guindani was born in Milan in 1958 and has been Director of Eni since May 2014. He is currently Chairman of the Board of Directors of Vodafone Italia SpA, Board member of FINECOBank SpA, Salini-Impregilo SpA and Cefriel S.cons.r.l. and of the Italian Institute of Technology, Board Member of Civita Foundation, Assonime and Confindustria, Member of the Executive Board of Assotelecomunicazioni, member of the Executive Board of Confindustria Digitale and Vice President for Universities, Innovation and Human Capital of Assolombarda. From 1982 to 1986 he was Relationship Banker at Citibank N.A. He then became International Finance Director in Montedison SpA (Enimont SpA) until 1992. He was Group Finance, Budget and Reporting Manager at European Vinyls Corporation SA/NV (1992-1993). In 1993 he became Head of Foreign Finance in Olivetti SpA. From 1995 to 2004 he was Chief Financial Officer of Vodafone Italy and of Vodafone South Europe, Middle East & Africa Region. From 2004 to 2008 he was Chief Executive Officer of Vodafone Italy. He was also Director of Pirelli & C. SpA (2011-2014), Carraro SpA (2009-2012) and Sorin SpA (2009-2012). He graduated with a degree in Business from the Università Luigi Bocconi in Milan.

Karina A. Litvack was born in Montreal in 1962 and has been a Director of Eni since May 2014. She is currently a member of the Global Advisory Council of Cornerstone Capital Inc., a member of the Advisory Board of Bridges Ventures LLC, a member of the CEO Sustainability Advisory Panel of SAP AG, a member of Business for Social Responsibility and of Yachad and a member of the Advisory Council for Transparency International UK. 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

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Transparency Initiative (2003-2009) and of the Primary Markets Group of the London Stock Exchange Primary Markets Group (2006-2012). She graduated with a degree in Political Economy from 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 a founding partner of Tokos Srl, a consulting firm for securities investment, Chairman of Società Metropolitana Acque Torino SpA and 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, serving as a Board member from 2008 to June 2011.

Diva Moriani was born in Arezzo in 1968 and has been a Director of Eni since May 2014. She is currently Executive Vice Chairman of Intek Group SpA, CEO of KME AG Vorstand, a German holding company of KME Group, Chairman of KME S.r.l., Member of the Supervisory Board of KME Germany GmbH and Director of Assicurazioni Generali SpA, Moncler SpA, Ergycapital 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 SpA, with an investment strategy focused on “Special Situations”. She graduated with a degree in Economics from the University of Florence.

Fabrizio Pagani was born in Pisa in 1967 and has been a Director of Eni since May 2014. He is currently the Head of the Technical Secretariat of the Ministry of Economy and Finance. He was Deputy Director of the International Training Programme for Conflict Management at the S. Anna School of Advanced Studies 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’s Office from 2006 to 2008, a 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 with a degree in international studies from the Sant’Anna School of Advanced Studies, Pisa, and has a Master’s Degree from the European University Institute, Florence.

Alessandro Profumo was born in Genoa in 1957 and has been Director of Eni since July 2015. He is currently Chairman of Equita SIM, of Appeal Strategy & Finance S.r.l. and member of the Supervisory Board of Sberbank. He is also a Board member of TOG “Together To Go”. In February 2012 he was appointed member of the International Advisory Board of Itau-UniBanco. He began his career in 1977 at the Banco Lariano, becoming Branch Manager in Milan. In 1987 he joined McKinsey, where he was Project Manager in the strategy area for the finance sector. In 1989 he was appointed Head of relations with financial institutions and integrated development and organization projects at Bain, Cuneo e Associati (now Bain & Company). In 1991 he left the field of company consultancy to join RAS, Riunione Adriatica di Sicurtà, where as General Manager he was responsible for the banking and parabanking sectors. He was also in charge of the yield increase of RAS’s bank and of the other companies in the group operating in the field of asset management. In 1994 he joined Credito Italiano as Joint Central Manager and was in charge of Programming and Control, becoming General Manager in 1995. In 1997 he was appointed Chief Executive Officer of Credito Italiano and subsequently of Unicredit, a position he held until September 2010. On an international level he was Chairman of the European Banking Federation and Chairman of the IMC in Washington. In May 2004 he was decorated as Cavaliere del Merito del Lavoro.

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From 2006 to 2014 he was Director of Bocconi University in Milan and from 2011 to 2014 he was Director of Eni and he was Chairman of Banca Monte dei Paschi di Siena from 2012 to 2015. He was Chairman of CASL (Comitato per gli Affari Sindacali e del Lavoro dell'ABI) from 2014 to 2015 and in February 2012 he was appointed a member of the "High-level Expert Group" on structural reform of the EU banking sector; he left the Group when he was appointed Chairman of Banca Monte dei Paschi di Siena. He graduated with a degree in business administration from the Università Luigi Bocconi of Milan.

Senior Management

The table below sets forth the composition of Eni's Senior Management as at December 31, 2016. 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	General Manager of Eni	2014		35		61
Luca Bertelli	Chief Exploration Officer	2014		32		58
Roberto Casula	Chief Development, Operations & Technology Officer	2014		28		54
Alberto Chiarini	Chief Retail Market Gas & Power Officer	2016		27	(1)	53
Claudio Granata	Chief Services and Stakeholder Relations Officer	2014		33		56
Massimo Mantovani	Chief Midstream Gas & Power Officer	2016	(2)	23		53
Massimo Mondazzi	Chief Financial Officer	2014	(3)	24		53
Giuseppe Ricci	Chief Refining & Marketing Officer	2016	(4)	31		58
Antonio Vella	Chief Upstream Officer	2014		33		59
Marco Bollini	Legal Affairs Department Senior Executive Vice President	2016	(5)	19		50
Marco Petracchini	Internal Audit Department Senior Executive Vice President	2011	(6)	17		52
Roberto Ulissi	Corporate Affairs and Governance Department Senior Executive Vice President Board Secretary and Corporate Governance Counsel	2006	(7)	10		54
Marco Bardazzi	External Communication Department Executive Vice President	2015		1		49
Luca Cosentino	Energy Solutions Department Executive Vice President	2015		13		55
Pasquale Salzano	Government Affairs Department Executive Vice President	2015	(8)	5		43
Luca Franceschini	Integrated Compliance Department Executive Vice President	2016	(9)	25		50
Jadran Trevisan	Integrated Risk Management Executive Vice President	2016	(10)	16		55

(1)
It includes the period he served at Saipem SpA

(2)
Prior to October 17, 2016, he was Chief Legal and Regulatory Affairs.

(3)
Prior to September 12, 2016, he was Chief Financial and Risk Management Officer.

(4)
Prior to September 12, 2016 he was Executive Vice President Health, Safety, Environment & Quality Department, but he did not report to Chief Executive Officer.

(5)
Prior to October 17, 2016, he was Executive Vice President International and Finance Legal Department, but he did not report to Chief Executive Officer.

(6)
Since 2014 the Senior Executive Vice President of the Internal Audit Department reports hierarchically to the Board of Directors and, on its behalf, to the Chairman, without prejudice to its functional dependence on the Control and Risk Committee and on the Chief Executive Officer (in his capacity as Director in charge of the Internal Control and Risk Management System).

(7)
Since 2014, the Board Secretary has also served as Corporate Governance Counsel. The Board Secretary reports hierarchically and functionally to the Board of Directors and, on its behalf, to the Chairman.

(8)
Prior to February 19, 2015, he was Senior Vice President Government Affairs.

(9)
Prior to September 12, 2016, he was Executive Vice President Legal Compliance and Regulatory Department, but he did not report to Chief Executive Officer.

(10)
Prior to September 12, 2016 he reported to the Chief Financial and Risk Management Officer.

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The Chief Exploration Officer, the Chief Development, Operations & Technology Officer, the Chief Upstream Officer, the Chief Midstream Gas & Power Officer, the Chief Refining & Marketing Officer, the Chief Retail Market Gas & Power Officer, the Chief Financial Officer, the Chief Services & Stakeholder Relations Officer, the Senior Executive Vice President Legal Affairs Department, the Senior Executive Vice President Internal Audit Department, the Senior Executive Vice President Corporate Affairs and Governance Department, as well as the Executive Vice President Energy Solutions Department, the Executive Vice President External Communication Department, the Executive Vice President Government Affairs Department, the Executive Vice President Integrated Compliance Department, the Executive Vice President Integrated Risk Management, the Chief Executive Officer of Versalis SpA and the Chief Executive Officer of Syndial SpA are members of the Management Committee, 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 Department.

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.

The Senior Executive Vice President of the Internal Audit Department 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 in 1958. He graduated cum laude with a degree in geology in 1983 from the University of Florence. In 1984 joined Eni's geophysics division where he worked first as a researcher in the development of 3D seismic prospecting technology and subsequently as a manager of 3D seismic prospecting programs, and specializing in seismic-stratigraphy. In 1994, he was appointed Manager of seismic-stratigraphy applications and in 1999 expanded the technical-managerial scope of his activities becoming Eni's Manager of geological and geophysical services. At the end of 2001, his career took a new international turn with roles of increasing managerial complexity over a period of eight years, starting in Norway where he was Technical Director and Deputy Managing Director of Norsk Agip. In 2003, he was appointed Managing Director of Eni Indonesia and in 2006, moved to Egypt as General Manager and Managing Director, a role he covered also at Eni Angola in 2007. In 2009, he returned to Eni's headquarters as Senior Vice President Global Exploration. At the beginning of 2010, he was appointed Executive Vice President of Exploration and Unconventional. Since July 1, 2014, he has been Eni's Chief Exploration Officer.

Roberto Casula was born in Cagliari in 1962. He graduated with a degree in mining engineering from the University of Cagliari and joined Eni in 1988 as a reservoir engineer. He spent the first years of his professional life working at oilfields in Italy before moving to West Africa where he was appointed Chief Development Engineer. He returned to headquarters in 1997 as coordinator business development activities for Africa and the Middle East, contributing to a number of new initiatives and portfolio activities. In 2000, he became project technical services manager and in 2001, moved to the Middle East as Project Director on a giant gas production project. From 2004 to 2005, he held a number of managerial positions in the Exploration & Production Division, becoming Chief Executive Officer of Eni Mediterranea Idrocarburi SpA, engaged in oil&gas exploration and production in Sicily. At the end of 2005, he was appointed Managing Director of Eni's activities in Libya, where he remained for two years and concluded the renegotiation of oil contracts and launched an important program of social projects. In October 2007, he became head of operational and business activities in sub-Saharan Africa as Senior Vice President, based in Nigeria. In December 2011, he was appointed Executive Vice President Africa and Middle East Region, also coordinating the Mozambique programme for the development of the Mamba and Coral discoveries. From 2014 to May 2016, he was a member of the Board of Directors of the Eni Foundation. Since July 1, 2014, he has been Eni's Chief Development, Operations & Technology Officer.

Alberto Chiarini was born in Milan in 1963. After taking a degree in political science and a course of specialization at the Scuola Enrico Mattei, he joined Eni in 1989. He began his career in an international context, in the business/finance area, in positions of growing responsibility in a number of countries (including the United Kingdom, Congo, Libya and Holland) rising to the position of Managing Director of Eni UK. He returned to Italy in 2006 as head of Planning and Control at the Exploration and Production division and was subsequently appointed as Eni's Executive Vice President Global Procurement and Strategic Sourcing. In 2011 he was appointed Chief Executive of Syndial, the Eni subsidiary that provides integrated services in the field of environmental remediation. On December 6, 2013 he was appointed Chief Financial and Compliance Officer of Saipem SpA with responsibility for Finance, Legal Affairs & Compliance and ICT, overseeing in particular the recapitalisation and refinancing of the company. He was appointed as Chief Retail Market Gas & Power Officer on September 12, 2016.

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 he 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 given responsibility for Staff and Organization within Eni Servizi Amministrativi, a company that was set up to centralize Eni's administrative activities. In 2001, he took over the management of Eni's territorial divisions, for which he structured the management of the 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), characterized by the mergers by incorporation of Snam and AgipPetroli and the redefinition of the organizational structures for the staff. In the same year he was also appointed as Director of personnel and organization 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 the human resources and organization activities. He also collaborated with the top management in the reorganization of macro processes for the Division and promoted Change Management initiatives. From 2006, he has been a Board Member of Eni International Resources Ltd, and from 2012 to 2013, he has been appointed as Chairman of the Board of Eni International Resources Ltd. From 2012 to March 2015, he has been a board member of Eni UK Ltd. Since 2013, he has been Executive Vice President Sustainable Development, Safety, Environment and Quality at E&P, with responsibility 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. Since November 2014, he has been Chairman of the Board of Eni Corporate University. Since July 1, 2014, he has been Eni's Chief Services & Stakeholder Relations Officer.

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 and teaches post-graduate courses. After qualifying to practice law in Italy and UK he worked for a 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 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 S.p.A. He has been Chief Legal and Regulatory Affairs of Eni from 2014 to 2016, the department managed all legal and energy regulatory issues of Eni and its unlisted subsidiaries. From 2005 to 2016 he was member of the Eni S.p.A. Watch Structure. He was a member of the Board of Directors of Snam Rete Gas S.p.A. from 2005 to 2012 and of the Board of the University of Bologna from 2011 to 2012. He has been Chairman of Syndial S.p.A. from 2016 to 2017. He is currently Chairman of Eni Trading & Shipping S.p.A. He is also Eni Representative on the Eurogas Governing Board and on its Executive Committee since November 2016.

Between 2011 and
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2014 he was 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. Massimo Mantovani has been Eni's Chief Midstream Gas & Power Officer since 17 October 2016.

Massimo Mondazzi was born in Monza in 1963. He graduated with a degree 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 head of the Division. 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. From 2014 until September 2016, alongside his role as Eni's Chief Financial Officer, he was also responsible for Eni's Integrated Risk Management department.

Giuseppe Ricci was born in Casale Monferrato in 1958. He has a degree in chemical engineering. 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. Since 2016 he has been a board member of Eniservizi. He was appointed as Chief Refining & Marketing Officer on September 12, 2016.

Antonio Vella was born in 1957. He graduated with a degree in engineering from the Turin Polytechnic in 1982 and joined the Eni Group in 1983. He began 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 then, 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 and Saudi Arabia) for Eni's Exploration & Production Division. In 2009, he was appointed Executive Vice President Operations for the Exploration & Production Division. In December 2012, he was appointed Executive Vice President for Central Asia, the Far East and the Pacific Area. Since July 2014, he has been a Board Member of Eni Foundation. Since July 1, 2014, he has been 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 S.p.A., 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

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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.

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 Department.

Roberto Ulissi was born in Rome in 1962. He's 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 has been 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 of Banor SIM. He has also been 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.

Marco Bardazzi was born in Prato in 1967. A journalist by trade, he worked in the media business for 28 years, before joining Eni in 2015. He has achieved an extensive experience in foreign policy and digital communications, particularly related to European and American realities (he lived and worked in the United States for nine years). Between 2009 and 2015, he has been Managing Editor and Digital Editor at "La Stampa", a leading European newspaper based in Turin, Italy. He has been a key member of the "La Stampa" team that has worked on its transformation from a traditional newspaper founded in 1867 to an integrated digital news organization, thus creating an innovative "concentric circle" multiplatform newsroom. He has also been a co-founder of the "Europa" 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, covering every aspect of American life for the Italian media. Among other things, he has covered the 2000 Bush-Gore electoral race for the White House; the first international Al Qaeda trial in Manhattan; the September 11, 2001 attack on America; the war in Afghanistan; the war in Iraq; the 2004 and 2008 presidential campaigns; he has visited and reported on the Guantanamo detention camp at U.S. Navy Guantanamo Bay base, Cuba; he has covered the 2008 financial crisis, and he has extensively reported on the American digital, energy and manufacturing businesses. He teaches a class on "Journalism innovation" in the Master on Journalism program at ALMED-Università Cattolica del Sacro Cuore, Milan. 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. Since February, 16, 2015, he has been External Communication Department 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 Department.

Pasquale Salzano was born in Pomigliano d'Arco (Naples) in 1973. In 1996, he graduated with Honors with a degree in Law from the University "Federico II" in Naples and in 2000 obtained a PhD in international law from the University of Siena. From 1996 to 1999, he collaborated with Prof. Benedetto Conforti at the Chair of International Law at the University of Naples and in 2000, qualified as a Lawyer at the Naples Court of Appeals. He began his career as a diplomat in December 1999 and from January 2000 to July 2001, worked on legal and institutional issues regarding the European Union at the General Directorate for European Integration of the Italian Ministry of Foreign Affairs. In 2001, in the aftermath of the Balkan conflict, Pasquale Salzano was appointed Chief of Staff of the international OSCE Mission in Belgrade and the following year was posted by the Italian Government to Pristina to establish and manage the Italian Liaison Office at the Special Representative of the Secretary-General of the United Nations in Kosovo, which subsequently became the Italian Embassy. From 2005, he was in New York at the Permanent Mission of Italy to the United Nations and, after about two years, was posted to Rome to the Office of the Diplomatic Adviser to the Prime Minister where, in view of the Italian Presidency of the G8, was appointed by the Prime Minister as Head of the Sherpa Office for the G8/G20. In 2009, he was selected by the OECD Secretary-General as Director of the Heiligendamm/L'Aquila Process in Paris. From January 2011, he was seconded by the Ministry of Foreign Affairs to Eni, where he was appointed Vice President, International Institutional Relations in the Department of Institutional Relations and Communications and Vice President of Eni-USA's Representative office. He is a Young Global Leader of the World Economic Forum, is a Member of the Board of the European Council on Foreign Relations (ECFR) Italy, the Scientific Committee of the Rome-Mediterranean Foundation and the National Assembly of UNICEF Italy. He is a member of the Institute for International Affairs (IAI) and the Institute for International Political Studies (ISPI). From July 1, 2014 to 2015 he was Eni's Senior Vice President Government Affairs. Since February 19, 2015, he has been Eni's Executive Vice President Government Affairs Department.

Luca Franceschini was born in Milan in 1966. He graduated with a degree 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 S.p.A., 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 antitrust 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,

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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

Board members' emoluments are determined by the Shareholders' Meeting, while the emoluments of the Chairman and CEO, in relation to the powers entrusted to them, are determined by the Board of Directors, which considers relevant proposals made by the Compensation Committee after consultation with the Board of Statutory Auditors.

Moreover, in accordance with the applicable Italian laws and regulations (Article 123-ter of Legislative Decree No. 58 of February 24, 1998 and Article 84-quater of Consob Decision No. 11971 of May 14, 1999, and subsequent modifications) and in line with the Corporate Governance Code recommendations for Italian listed companies, the Board of Directors approves and submits to the annual Shareholders' Meeting advisory vote, the first section of the Remuneration Report which describes the Remuneration Policy Guidelines adopted for Directors and other Managers with strategic responsibilities[5].

The main elements of the 2017 remuneration policy and of the compensation paid in 2016 to Directors, Statutory Auditors, CEO and General Manager and other Managers with strategic responsibilities, are described below.

2017 Remuneration Policy Guidelines

This chapter contains the Remuneration Guidelines for the new 2017-2020 term, approved by the Board of Directors on February 28, 2017 for the Directors who will be appointed at the Shareholders' Meeting on April 13, 2017. The new Board of Directors will retain the prerogative to determine, specific remuneration for the exercise of delegated powers and for participating on Board Committees, based on a proposal by the Compensation Committee. The Shareholders' Meeting will retain the prerogative to approve the Share-based Variable Incentive Plans.

Furthermore, the Remuneration Guidelines below for Directors in office until April 13, 2017 are also briefly outlined. These were already extensively discussed in the Remuneration Report 2016 and reflect the decisions made by the Board of Directors on May 28, 2014 for the 2014-2017 term.

Policies For Directors During The 2017-2020 Term Of Office

The main novelty of the Remuneration Policy in the new term of office is the comprehensive review of the variable incentive scheme for the Chief Executive Officer and General Manager and for all other Senior Managers in order to simplify the incentive scheme's overall architecture (which will be broken down into two incentive plans instead of three) and further align performance objectives with shareholder expectations. More specifically, the new incentive scheme provides for the introduction of:

- a Short-Term Monetary Plan with the deferral of a portion of the accrued bonus, which will start from the assignment of the 2017 objectives with the first payment in 2018, to replace the previous Annual Monetary Incentive and Deferred Monetary Incentive plans.

- a Long-Term Performance Share Plan 2017-2019, with first attribution in 2017, to replace the previous Long-Term Monetary Incentive Plan (subject to approval by the Shareholders' Meeting on April 13, 2017).

(5)
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", pursuant to Consob regulations. Eni Managers with strategic responsibilities, other than Directors and Statutory Auditors, are those who sit on the Management Committee and, in any case, those who report directly to the Chief Executive Officer.

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For the Chairman and the Non-Executive Directors, adjustments are proposed for the remuneration envisaged for delegated powers and for participating on Board Committees compared with median levels in the reference markets.

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 in the international Oil & Gas sector, with regard to upstream activities in particular, and in line with the company's strategy to increase its focus on the business. More specifically, the comparator group has been expanded to include the main listed companies in the Oil & Gas sector, which are Eni competitors at the international level and possess comparable business characteristics (Anandarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Statoil and Total).

This panel also constitutes the Peer Group used for the relative comparison of Eni performance in the new Long-Term Performance Share Plan.

For the Chairman and the Non-Executive Directors, the positioning of remuneration is assessed by comparing similar roles in the Top Italy Panel, composed of the main companies listed on the FTSE MIB (Assicurazioni Generali, Atlantia, Enel, Intesa Sanpaolo, Leonardo-Finmeccanica, Luxottica, Mediaset, Mediobanca, Poste Italiane, Snam, Terna, TIM, Unicredit).

For Managers with strategic responsibilities, the positioning of remuneration is assessed by comparing roles with the same level of managerial responsibility and complexity in national and international panels of companies in the industrial sector.

General principle of clawback

Clawback mechanisms will be adopted, through a specific regulation proposed by the Compensation Committee and approved by the Board of Directors, allowing the variable remuneration components already paid and/or granted to be reclaimed, or those subject to deferral to be withheld, where their achievement was based on data that was subsequently proven to be manifestly misstated, or allowing the recoupment of all the incentives for the year (or years) in which subsequent checks confirm the fraudulent alteration of the results data used to obtain the right to incentives, and/or the commission of serious and deliberate violations of the law and/or regulations, the Code of Ethics or the Company rules, if relevant to the employment and trust relationship, without prejudice to any other action permitted by law and regulations to protect the interests of the Company. The regulation provides that the activation of recoupment claims (or revocation of incentives awarded but not yet paid) must take place, once the checks have been completed, within three years of payment (or award) in the case of error, and within five years in the case of fraud.

Chairman of the Board of Directors

Remuneration for the delegated powers

Remuneration will be defined in line with the decisions taken by the Shareholders' Meeting on 13th April 2017 and with the median levels in the reference market, taking the delegated powers into account.

Payments due in the event of termination of office or employment

No specific severance payments are provided for the Chairman, nor do any agreements exist for indemnities in the case of early termination of office.

Non-executive directors

Remuneration for participation on Board Committees

The Policy Guidelines for Non-Executive and/or Independent Directors provide for the adjustment of the additional annual remuneration for participating on Board Committees in line with the median levels in the reference market, taking due account of commitment in terms of meetings and their duration. More specifically, for the 2017-2020 term, the following remuneration is proposed:

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- for the Control and Risk Committee, annual remuneration consists of €70,000 for the Chairman and €50,000 for the other members;

- for the Compensation Committee and the Sustainability and Scenarios Committee, the annual remuneration consists of €50,000 for the Chairman and €35,000 for the other members;

- for the Nomination Committee, the annual remuneration consists of €40,000 for the Chairman and €30,000 for the other members.

Payments due in the event of termination of office or employment

No specific severance payments are provided for the Non-Executive Directors, nor do any agreements exist for indemnities in the case of early termination of office.

Chief Executive Officer and General Manager

The Policy Guidelines for the Chief Executive Officer and General Manager take into account the specific delegated powers granted in accordance with the By-laws, the instructions contained in the chapter "Purpose and general principles of the Remuneration Policy" as well as the remuneration levels and best practices in the reference Oil & Gas panel.

Fixed remuneration

Fixed remuneration (FR) will be set by the new Board of Directors based on a proposal of the Compensation Committee in relation to the delegated powers and positions held, taking into account the median levels in the reference market. Fixed remuneration includes the remuneration for Directors established by the Shareholders' Meeting on April 13, 2017, as well as any compensation that may be due for participating on the Board of Directors of subsidiaries or associated companies.

Variable incentive plans

Short-Term Monetary Plan with deferral

The new Short-Term Monetary Plan with deferral of a portion of the accrued bonus brings together the previous Annual Monetary Incentive and Deferred Monetary Incentive plans.

Compared with the previous Plans, the performance scales have been extended to include achievement of results that are above or far above the target levels.

In this Plan, a portion of the incentive is paid annually and a portion is deferred for a three-year period, as described below.

The Short-Term Monetary Plan with deferral is linked to the achievement of the 2017 objectives approved by the Board of Directors on February 28, 2017. These objectives keep the structure focused on the essential goals consistent with the guidelines outlined in the Strategic Plan and balanced against the interests of the various stakeholders, in terms of economic and financial results (25%), operating results and sustainability of the economic performance (25%), environmental sustainability and human capital (25%), efficiency and financial strength (25%). The value of each objective, at target performance level, is aligned with the budgeted value.

Each objective is measured in accordance with a performance scale of 70 to 150 points (target=100), in relation to the weight assigned to each target (below 70 points, the performance of each target is considered to be zero). For the purposes of the incentive award, the minimum overall performance is 85 points. This Plan provides for remuneration calculated with reference to a minimum (performance=85), target (performance=100) and maximum (performance=150) multiplier, equal respectively to 85%, 100% and 150% to be applied to the target incentive, as determined by results achieved by Eni over the previous year.

Total incentive (TI) is calculated using the following formula:

TI = FR x % ITarget x Multiplier

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Where "ITarget" is the incentive percentage at target performance level, which is set at 150% of total fixed remuneration for the Chief Executive Officer.

The Plan conditions state that the total incentive is divided into 2 portions.

1)

a portion paid annually (IYear) equal to 65% of the total incentive.

Iannual = TI x 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.

Annual performance	<85	85	100	150
		threshold	target	max
Annual incentive (% of Fixed Rem)	0%	83%	98%	146%

2)

a deferred portion equal to 35% of the total incentive, subject to further performance conditions during a three-year vesting period.

The deferred portion payable at the end of the vesting period is determined by multiplying the initial deferred portion by the payment multiplier. The latter is given by the average of the three annual multipliers, each determined during the three-year period in relation to the performance achieved, based on Eni's annual objectives. The multiplier of the deferred portion depends on the performance achieved, with reference to a minimum (performance=85), target (performance=100) and maximum (performance=150) incentive level, equal respectively to 85%, 130% and 230% of total fixed remuneration.

The Deferred Incentive (DI) payable at the end of the three-year deferment period is calculated using the following formula:

DI = TI x 35% x 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.

3-year Average performance	<85	85 threshold	100 target	150 max
Deferred incentive (% of Fixed Rem)	0%	38%	68%	181%

Long-Term Performance Share Plan

The Chief Executive Officer participates in the Long-Term Performance Share Plan 2017-2019, which also applies to Senior Managers, deemed critical for the business, subject to approval by the Shareholders' Meeting on April 13, 2017. The Plan replaces the previous Long-Term Monetary Incentive Plan as a tool to incentivize and promote the loyalty of the most critical management positions for the company, ensuring achievement, in line with international best practices, of the following additional objectives:

- strengthening the culture of business risk management from the perspective of shareholders by adopting shares as an incentive;
- setting a more challenging minimum incentive threshold, positioned at median level;
- further aligning performance conditions with the long-term expectations of shareholders, using:

(i)
an assessment of the 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 (Peer Group);

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(ii)

further incentivize the capacity to develop industrial assets, measured using the increase in the Net Present Value of hydrocarbon reserves in the medium-long term (in accordance with the assessment method defined by the SEC), measured in relative terms compared with the designated peer group.

The Plan provides for three annual awards starting from 2017, each with a three-year vesting period.
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, corrected by the Eni Correlation Coefficient, compared with the equivalent adjusted TSR measure for each company in the Peer Group, as shown in the following (50% weight):

TSRA - (TSRI x A,I)
Where:
TSRA: TSR of Eni or one of the companies in the Peer Group
TSRI: TSR of the Reference Stock Market Index of the company for which TSRA was calculated
A,I: Correlation Coefficient

2.

Net Present Value of proven reserves (NPV) vs the Peer Group, measured in terms of the annual percentage change, calculating the average annual performance in the three-year period (50% weight).

The reference Peer Group is described in the “Market references and Peer Group” section. (Anadarko, Apache, BP, Chevron, Conoco Phillips, ExxonMobil, Marathon Oil, Shell, Statoil 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% (Itarget) of total fixed remuneration, using the following formula.

$$\text{No.of Attributed Shares} = \frac{\text{FR x \% Itarget}}{\text{PriceAttr}}$$

Where the price of the award (PriceAttr) is calculated as the average of daily official prices (source Bloomberg) recorded in the 4 months before the date of the Board of Directors meeting that annually approves 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 0 and 180%, with a threshold set at the median level, in accordance with the scale shown below.

Performance Scale - Multiplier

Ranking										
1st	2nd	3rd	4th	5th	6th	7th	8th	9th	10th	11°
Multiplier										
180%	160%	140%	120%	100%	80%	0%	0%	0%	0%	0%
					Median positioning					

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Grantable shares are calculated using the following formula:

No.of Granted Shares = No.of Attributed Shares x Multiplier

The value levels of the Shares granted at the end of the vesting period, net of changes in the share price over the same period, are given below.

Weighted average 3-year performance	<26.6	26.6 threshold (*)	100 target	180 max
Value of Shares (% of Fixed Rem)	0%	40%	150%	270%

(*)

Achieved for example if the minimum level (6th place) is reached for the indicator of NPV of proven reserves, in at least two years of the three year vesting period.

For executives in services, 50% of the shares granted at the end of the vesting period are locked up for a period of 1 year after the grant date.

As the Plan is submitted to the Shareholders' Meeting for approval, it is also described in detail in the information document made available to the public on the Company website.

For both the deferred portion of the short-term incentive and the long-term share incentive, the clauses provided for all Managers in the respective Rules will apply in cases of termination of employment before the end of their term of employment. If their contract is not renewed, the natural expiry of the related vesting period is retained, in accordance with the performance conditions defined by each Plan.

Benefits

For the Chief Executive Officer and General Manager, the Policy Guidelines provide for insurance coverage for the risk of death or permanent disability and, as per provisions contained in the national collective bargaining agreement and the supplementary corporate agreements for Eni senior managers, enrolment in the supplementary pension plan ("FOPDIRE") as well as in the supplementary health plan (FISDE), together with a company car for business and personal use.

Pay Mix

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, composed of the short-term incentive deferral and the long-term share incentive valued using the international methodologies adopted for remuneration benchmarks. The pay mix, calculated by considering fixed remuneration as the base, is significantly focused on the variable components, with a dominant weighting attributed to the long-term component.

Payments due in the event of termination of office or employment

For the Chief Executive Officer and General Manager, in line with reference practice and with the provisions of the European Commission Recommendation No. 385 of April 30, 2009, as well as to protect the Company from potential competitive risks, the Policy provides for following payments:

- An indemnity supplementing the severance award payable upon termination of the employment relationship, due to non-renewal or early termination of the 2017-2020 term of office, including in the event of resignation due to a substantive reduction of delegated powers. Compensation for the CEO position will be defined in line with European Recommendations. For any employment relationship, the provisions set out for Managers with Strategic Responsibilities shall apply. Also with reference to criteria 6.C.1.g of the Italian Corporate Governance Code, this compensation is not due in the event of dismissal for "just cause" under Art. 2119 of the Italian Civil Code, or in the event of resignation as Chief Executive Officer prior to the expiry of the term in office, unless triggered by either the above-noted reduction of delegated powers, or in the event of death as governed by Art. 2122 of the Italian Civil Code;

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- Any non-competition agreement to protect the Company's interests, with specific compensation as a proportion of annual remuneration, as well as in relation to the rules of application, extent and duration of the commitments.

Policies for Directors during the 2014-2017 term of office

The Policy Guidelines for the term of office that expires at the Shareholders' Meeting on 13th April 2017 are summarized below.

Chairman of the Board of Directors

Remuneration for delegated powers

A fixed remuneration for the delegated powers of €148,000 is provided for the Chairman of the Board of Directors, in addition to remuneration for the position determined by the Shareholders' Meeting on May 8, 2014, amounting to €90,000, in compliance with the maximum of €238,000 defined by the same Shareholders' Meeting. These Guidelines do not provide for variable remuneration.

In 2017, these remuneration components will be paid pro-rata with respect to the period in office that ends with the Shareholders'Meeting called to approve the Financial Statements as at December 31, 2016.

Payments due in the event of termination of office or employment

No specific severance payments are envisaged for the Chairman, nor do any agreements exist for indemnities in the case of early termination of office.

Benefits

The Chairman is granted insurance coverage for the risk of death or permanent disability.

Non-executive Directors

Remuneration for participation on Board Committees

Non-executive and/or Independent Directors receive an additional annual remuneration[6] for participating on Board Committees, as follows:

- for the Control and Risk Committee, the remuneration amounts to €60,000 for the Chairman and €40,000 for the other members;

- for the Compensation Committee, the Sustainability and Scenarios Committee and the Nomination Committee the remunerations amount to €30,000 for the Chairman and €20,000 for the other members.

In 2017, this remuneration will be paid pro-rata with respect to the period in office that ends with the Shareholders' Meeting of April 13, 2017.

Payments due in the event of termination of office or employment

No specific severance payments are provided for the Non-Executive Directors nor do any agreements exist that provide for indemnities in the case of early termination of office.

Chief Executive Officer and General Manager

For the Chief Executive Officer and General Manager, the Policy Guidelines reflect the resolutions passed by the Board of Directors on May 28, 2014, taking into account the specific delegated powers granted in accordance with the Articles of Association, the instructions contained in the chapter "Principles and general purposes of Eni Remuneration Policy", as well as the 25% reduction of the

(6) This remuneration supplements the one established by the Shareholders' Meeting of May 8, 2014, for the remuneration of Non-executive Directors, amounting to €80,000 annual gross.

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maximum payable overall remuneration of the previous mandate, in accordance with the Shareholders' resolution of May 8, 2014. The remuneration envisaged by the Board in relation to the delegated powers includes both the compensation for Directors determined by the Shareholders' Meeting on May 8, 2014, as well as any compensation that may be due for participating on the Board of Directors of Eni's subsidiaries or associated companies.

Fixed remuneration

For the Chief Executive Officer and General Manager total fixed remuneration is set at a gross annual amount equal to €1,350,000, of which €550,000 for the position of Chief Executive Officer and €800,000 for the position of General Manager.

The remuneration envisaged by the Board in relation to the powers delegated includes both the remuneration for Directors determined by the Shareholders' Meeting on May 8, 2011, as well as any compensation that may be due for participating on the boards of directors of Eni's subsidiaries or associated companies.

In 2017, these remuneration components will be paid pro-rata with respect to the period in office that ends with the Shareholders' Meeting of April 13, 2017.

In his capacity as 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 provided by the relevant national collective labor agreement for senior managers and complementary Company level agreements.

Annual variable incentives

The annual variable incentive linked to achieving the targets set for 2016 will be paid in 2017.

Deferred Monetary Incentive Plan

In 2017, the Chief Executive Officer and General Manager participates in the last award of the Deferred Monetary Incentive (DMI) Plan 2015-2017, also envisaged for all the Company's senior managers, associated with Company performance measured in terms of Earnings Before Taxes (EBT).

Long-Term Monetary Incentive Plan

The Long-Term Monetary Incentive Plan 2014-2016 ended in 2016 with the last award. The new Long-Term Performance Share Plan 2017-2019 will be implemented from 2017. This Plan has already been described in the section "Policies for the 2017-2020 term of office" and in the information document made available to the public on the Company website.

Benefits

For the Chief Executive Officer and General Manager the Policy Guidelines provide for insurance and healthcare coverage defined by the national collective bargaining agreement and the supplementary corporate agreements for Eni senior managers, as well as a company car for business and personal use.

Payments due in the event of termination of office or employment

For the Chief Executive Officer and General Manager, in line with sector practices and with the provisions of the European Commission Recommendation No. 385 of April 30, 2009, as well as to protect the Company from potential competitive risks, the Policy provides for following payments:

- an indemnity supplementing the severance award, with mutual exemption from notice, is payable upon termination of the employment relationship, due to non-renewal or early termination of the 2014-2017 term of office, including in the event of resignations caused by a substantial reduction of delegated powers. This indemnity is equal to two years of total fixed remuneration (€1,350,000), for a total gross amount equal to €2,700,000. It should also be noticed that there is an ongoing analysis of the effective enforceability of the agreed framework, partly with reference to legislative changes following the conclusion of the contract with the Chief Executive Officer and General Manager. Also with reference to the recommendation 6.C.1g) of the Italian

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Corporate Governance Code, note that, in relation to the applicable contractual provisions, this compensation is not due in case of dismissal for "just cause" under Article 2119 of the Italian Civil Code or in cases of resignations as Chief Executive Officer before the expiry of the term in office , unless triggered by a reduction of delegated powers, or in the event of death governed by Article 2122 of the Italian Civil Code;

- non-competition agreement to protect the Company's interests that can be activated at the sole discretion of the Board of Directors through the exercise of an option right, the validity of which applies only as of the one set of a second term (if appointed), in exchange for a total option fee of €500,000 gross to be paid in three annual installments. If the option is exercised by the Board and the agreement is implemented, a non-compete award will be paid subject to a commitment by the Chief Executive Officer and General Manager not to undertake, for the twelve months following the expiry of the term, any activities of Exploration & Production activities potentially in competition with Eni in key markets in Europe, America, Asia and Africa. This amount will be set by the Board of Directors as the sum of two components: (i) a fixed component of €1,500,000; and (ii) a linearly determined variable component based on the average annual performance of the previous three years (equal to 0 for performance below or equal to the target and to €750,000 for maximum performance), and will be paid at the expiry of the term of the agreement. The variable component is calculated by taking into consideration the annual performance related to the annual Variable Incentive Plan. Any violation of the non-competition agreement will result in the non-payment of the consideration (or its restitution, where the violation is identified by Eni after the payment), and the obligation to pay damages set by mutual agreement in an amount equal to twice the amount of the non-competition agreement, without prejudice to Eni's right to seek fulfillment in specific form.

2017 policies for MANAGERS WITH STRATEGIC RESPONSIBILITIES

For Managers with Strategic Responsibilities, the Guidelines provide for 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 the national collective bargaining agreement for senior managers.

In the new 2017-2020 term of office, starting from April 13, 2017, the new Long-Term Share Incentive Plan and Short-Term Variable Incentive Plan with Deferral – intended for the Chief Executive Officer who will be appointed by the Shareholders' Meeting of April 13, 2017 - will also apply to Managers with Strategic Responsibilities. The Plans applying to the previous term will be implemented until April 13, 2017.

Market references

For Managers with Strategic Responsibilities, the positioning of remuneration is assessed by comparing roles with the same level of managerial responsibility and complexity in national and international panels of companies in the industrial sector.

Fixed remuneration

Fixed remuneration is based on the role 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 2017 Guidelines provide for a selective approach to salary reviews, while maintaining appropriate levels to ensure competitiveness and motivation.

More specifically, the 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 reflect needs for retention and excellent performance.

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In addition, as Eni officers, Managers with Strategic Responsibilities are entitled to receive the allowances due for travel in Italy and abroad, in line with applicable provisions of the relevant national collective bargaining agreement for senior managers and supplementary Company agreements.

Variable incentive plans

Annual variable incentives

Starting with the assignment of the 2017 objectives and with the first payment in 2018, the annual variable Incentive Plan will be replaced by the new Short-Term Monetary Plan with deferral, already described for the Chief Executive Officer and General Manager.

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 perspective of stakeholder interests, as well as with the relevant individual targets, consistent with the responsibilities of the role played and the provisions of the Company's Strategic Plan. For Managers with Strategic Responsibilities the target incentive levels for the new Short-Term Monetary Plan differ depending on the role's level of responsibility and complexity and are equal to the sum of those set for the previous Annual Variable Incentive Plan and Deferred Monetary Incentive Plan (up to 100% of fixed remuneration).

The last award for the previous Annual Variable Incentive Plan will be paid in 2017, determined with reference to the performance goals set for Eni, the business area and individual performance in 2016.

Deferred Monetary Incentive Plan

Managers with Strategic Responsibilities participate in the last attribution of the Deferred Monetary Incentive Plan (DMI) 2015-2017, approved by the Board of Directors on March 12, 2015.

Long-term variable incentive plan

Managers with Strategic Responsibilities participate in the Long-Term Performance Share Plan (LTI) 2017-2019, approved by the Board of Directors on February 28, 2017 and submitted for approval 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 upon the level of their role and is limited, as in the previous long-term monetary incentive plan, to a maximum of 75% of fixed remuneration.

Benefits

For Managers with Strategic Responsibilities, in line with the policy implemented in 2016 as well as the provisions of the national collective bargaining agreement and supplementary Company-level agreements for Eni managers, the Policy Guidelines provide for enrolment in the supplementary pension plan (FOPDIRE) and health plan (FISDE), as well as insurance coverage for the risk of death or disability, together with a company car for business and personal use, and the possible assignment of housing based on operational and mobility requirements.

Pay Mix

The average target pay mix of the remuneration package for Managers with Strategic Responsibilities, with the application of both new incentive plans (short-term monetary plan with deferral and long-term performance share plan), calculated using the same valuation methods used for the Chief Executive officer and General Manager, highlights the balance between the fixed and variable components and, as regards the latter, the greater weighting of medium-long term variable incentives, in line with market best practice.

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Payments due in the event of consensual termination of employment

Managers with Strategic Responsibilities, as well as Eni senior managers, are entitled to the severance benefits for employment termination established by law and applicable national collective bargaining agreement, 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 the protection envisaged by the applicable national collective bargaining agreement, and consistent with application criterion 6.C.1 lett.g) of the Italian Corporate Governance Code. These criteria take into account the position held, the 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 criticality of the position held by the Manager, agreements containing non-competition clauses may also be entered into with payments defined in relation to the remuneration received and the scope, duration and effectiveness of the agreement.

COMPENSATION AND OTHER INFORMATION

Implementation of the 2016 remuneration policies

The following is a description of the remuneration decisions taken in 2016 for the Chairman of the Board of Directors, Non-executive Directors, Chief Executive Officer and General Manager, and other Managers with strategic responsibilities, in relation to their time in office.

The implementation of the 2016 Remuneration Policy, as verified by the Compensation Committee at the regular assessment required by the Corporate Governance Code, was found to be consistent with the 2016 Remuneration Policy, approved by the Board of Directors on March 17, 2016. This takes into account the resolutions passed by the Board of Directors on May 9 and May 28, 2014 on the remuneration of Non-executive Directors appointed Board Committees and on the definition of the remuneration of Directors with delegated powers, in accordance with the resolutions passed at the Shareholders' Meeting in accordance with Law No. 98/2013.

Chairman of the Board of Directors - Emma Marcegaglia

Fixed remuneration

The Chairman was paid the fixed remuneration approved for the office by the Shareholders' Meeting of May 8, 2014 of €90,000 gross and the remuneration approved by the Board of Directors Meeting of May 28, 2014, in relation to the exercise of delegated powers, amounting to €148,000 gross.

Benefits

The Chairman was granted insurance coverage against the risk of death and permanent disability, in accordance with the resolutions of the Board of Directors Meeting of May 28, 2014.

Non-executive Directors

The Directors were paid fixed remuneration approved by the Shareholders' Meeting of May 8, 2014 of €80,000 gross. The additional remunerations payable for participation on the Board Committees, as resolved by the Board of Directors Meeting of March 12, 2015, were also paid.

Chief Executive Officer and General Manager - Claudio Descalzi

Claudio Descalzi has held the office of Chief Executive Officer and General Manager since May 9, 2014, and before then he held the office of Chief Operating Officer (COO) of the E&P Division. Therefore, during 2016, Claudio Descalzi received the fixed remuneration and the annual variable incentive related to his current role of Chief Executive Officer and General Manager and the long term variable incentives accrued during his previous role, as detailed below.

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Fixed remuneration

The Chief Executive Officer and General Manager was paid the fixed remunerations approved by the Board of Directors Meeting of May 28, 2014, which also include the remunerations approved by the Shareholders' Meeting for all the Directors, equal to a total gross annual amount of €1,350,000.

Annual variable incentives

In line with the Remuneration Policy 2016, the Chief Executive Officer and General Manager was paid a gross annual variable incentive of €1,755,000 associated with the performance achieved during 2015 (130 points).

Deferred Monetary Incentive Plan

For the Chief Executive Officer and General Manager, the Board of Directors as its meeting of March 17, 2016, as proposed by the Compensation Committee and in accordance with the Remuneration Policy 2016, approved the assignment of the deferred monetary incentive of €864,000 gross, calculated based on the 2015 EBT results approved by the Board of Directors. Furthermore, in 2016 the Deferred Monetary Incentive assigned in 2013 to Claudio Descalzi, as COO of the Exploration & Production Division, vested, resulting in a gross amount paid equaled €659,000.

Long-Term Monetary Incentive Plan

For the Chief Executive Officer and General Manager, the Board of Directors at its meeting of 15th September 2016, as proposed by the Compensation Committee and in accordance with the Remuneration Policy 2016, approved the grant of the 2016 long-term monetary incentive award of 1,350,000 euros gross.

Furthermore, with regard to the Long-Term Monetary Incentive award granted in 2013 to Claudio Descalzi, as COO of the E&P Division, the performance achieved in the reference three-year period did not satisfy the conditions for payment of the incentive.

Benefits

The Chief Executive Officer and General Manager, in line with the resolution of the Board of Directors Meeting on May 28, 2014, was granted insurance coverage for death or permanent disability, and in compliance with the provisions of the national collective bargaining agreement and the supplementary corporate agreements for Eni senior managers, enrolment in the supplementary pension plan (FOPDIRE) as well as supplementary health plan (FISDE), together with a company car for business and personal use.

In 2016 Claudio Descalzi, for his role as Chief Executive Officer and General Manager, received a total of €3,120,000 and, for his previous role as COO of the E&P Division (held until May 8, 2014), €659,000 for the long term variable incentives accrued. Consequently, the total amount received was €3,779,000.

Managers with strategic responsibilities

Fixed remuneration

For the current Managers with Strategic Responsibilities, within the context of the annual salary review process envisaged for all managers, in 2016 selective adjustments were made to fixed remuneration, in cases of promotion to more senior levels, or in line with necessary market-driven adjustments . The total gross value of the fixed remuneration paid in 2016 to Managers with Strategic Responsibilities is shown in the section "Compensation paid in 2016", under the item "Fixed compensation".

Annual variable incentive

In March 2016, annual variable incentives were paid to Managers with Strategic Responsibilities in accordance with the Remuneration Policy and based on performance achieved in 2015.

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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, consistent with the provisions of the 2015 Eni Performance Plan.

Deferred Monetary Incentive Plan

Managers with Strategic Responsibilities were granted 2016 deferred monetary incentive awards, in accordance with the Remuneration Policy and on the basis of the 2015 EBT results approved by the Board of Directors on March 17, 2016, as proposed by the Compensation Committee. In 2016, the Deferred Monetary Incentive award granted in 2013 also vested.

Long-Term Monetary Incentive Plan

Managers with Strategic Responsibilities were granted their 2016 long-term monetary incentive award, determined in accordance with the Remuneration Policy. With regards to the Long-Term Monetary Incentive awards granted in 2013, the performance achieved in the three-year reference period did not satisfy the conditions for their payment.

Severance indemnity for end-of-office or termination of employment

During 2016, Managers with Strategic Responsibilities who accepted enhanced voluntary termination offers were paid, in addition to amounts due under legal and contractual obligations, additional amounts defined in line with company policy on early retirement incentives.

Benefits

For Managers with Strategic Responsibilities, in line with provisions in the national collective bargaining agreement and the 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), insurance coverage for the risk of death or disability, together with a company car for business and personal use.

COMPENSATION PAID IN 2016

The table below lists the individual remunerations to the Directors, Statutory Auditors, Chief Executive Officer and General Managers and, in aggregate form, to other Managers with strategic responsibilities. The remunerations received from subsidiaries and/or affiliates, except those 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:

- based on the criteria of competence, the column “Fixed remuneration” reports the fixed remuneration and fixed salary from employment due for the year, gross of the social security contribution and tax expenses to be paid by the employee; it excludes attendance fees, as these are not provided for. Details of the compensation are provided in the notes, and any indemnities or payments with reference to the employment relationship are indicated separately;

- based on the criteria of competence, the “Remuneration for participation in the Committees” column reports the compensation due to the Directors for participation in the Committees established by the Board. In the notes, compensation for each Committee on which each Director participates is indicated separately;

- the column “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 the related performance results by the relevant corporate bodies;

- based on the criteria of competence and taxability, the “Benefits in kind” column reports the value of the fringe benefits awarded;

- based on the criteria of competence, the “Other remuneration” column reports any other remuneration deriving from other services provided;

- the “Total” column details the sum of the amounts of all the previous items;

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- the "Fair value of equity remuneration" column reports the relevant fair value for the year related to the existing stock option Plans, estimated in accordance with international accounting standards, which assign the related cost in the vesting period; and

- the "Severance indemnity for end of office or termination of employment" column reports the indemnities accrued, even if not yet paid, for the terminations which occurred during the course of the financial year in question, or in relation to the end of the mandate and/or employment.

Remuneration paid to Directors, Statutory Auditors, Chief Executive officer and General Managers and other Managers with strategic responsibilities
(€ thousand)

First name and Surname	Note	Position	Period for which the position was held	Expiration of office (*)	Fixed remuneration	Remuneration for participation in the Committees	Variable non-equity remuneration		Bene in ki
							Bonuses and other incentives	Profit sharing	
Board of Directors									
Emma Marcegaglia	(1)	Chairman	01.01-12.31	05.2017	238 (a)				
Claudio Descalzi	(2)	Chief Executive Officer and General Manager	01.01-12.31	05.2017	1,350 (a)		1,755 (b)		15
Andrea Gemma	(3)	Director	01.01-12.31	05.2017	80 (a)	90 (b)			
Pietro Angelo Guindani	(4)	Director	01.01-12.31	05.2017	80 (a)	50 (b)			
Karina Litvack	(5)	Director	01.01-12.31	05.2017	80 (a)	63 (b)			
Alessandro Lorenzi	(6)	Director	01.01-12.31	05.2017	80 (a)	80 (b)			
Diva Moriani	(7)	Director	01.01-12.31	05.2017	80 (a)	51 (b)			
Fabrizio Pagani	(8)	Director	01.01-12.31	05.2017	80 (a)	50 (b)			
Alessandro Profumo	(9)	Director	01.01-12.31	05.2017	80 (a)	40 (b)			
Board of Statutory Auditors									
Matteo Caratozzolo	(10)	Chairman	01.01-12.31	05.2017	80 (a)				
Paola Camagni	(11)	Statutory auditor	01.01-12.31	05.2017	70 (a)				
Alberto Falini	(12)		01.01-12.31	05.2017	70 (a)				

		Statutory auditor						
Marco Lacchini	(13)	Statutory auditor	01.01-12.31	05.2017	70 (a)			
Marco Seracini	(14)	Statutory auditor	01.01-12.31	05.2017	70 (a)			
Other Managers with strategic responsibilities (**)	(15)	Remuneration in the company that prepares the Financial Statements			8,595		9,118	18
	Remuneration from subsidiaries and associates				458			
	Total				9,053 (a)		9,118 (b)	18
					11,561	424	10,873	20

Notes
(*)
The term of office expires with the Shareholders' Meeting approving the Financial Statements for the year ending December 31, 2016.

(**)
Managers who were permanent members of the Company's Management Committee during the course of the year together with the Chief Executive Officer and Division Chief Operating Officers, or who reported directly to the Chief Executive Officer (twenty-three managers).

(1)
Emma Marcegaglia - Chairman of the board of directors

(a) The amount includes the fixed remuneration of €90 thousand set by the Shareholders' Meeting on May 8, 2014 and the fixed remuneration for the delegated powers of €148 thousand approved by the Board on May 28, 2014.
(2)
Claudio Descalzi - Chief Executive Officer and General Manager

(a) The amount includes the fixed remuneration of €550 thousand for the position of Chief Executive Officer, which incorporates the remuneration set by the Shareholders' Meeting on May 8, 2014 for the position of Director, and the fixed remuneration of €800 thousand for the position of Chief Executive Officer; indemnities due for transfers, in Italy and abroad, in line with the provisions of the relevant national collective labour agreement for senior managers and of the Company's complementary agreements are added to this amount for a total of €19 thousand.
(b) The amount correspond to the variable annual incentive paid in 2016. To this amount is added the incentives of €659 thousand paid in 2016 for the position of COO of the E&P Division, held until May 8, 2014, related to the deferred monetary incentive assigned in 2013, calculated in relation to the performance targets achieved during the 2013-2015 vesting period.
(3)
Andrea Gemma – Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount includes the €40 thousand for participating in the Control and Risk Committee and €20 thousand for the Sustainability and Scenarios Committee and €30 thousand for the Nomination Committee.

(4)
Pietro Angelo Guindani - Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders’ Meeting of May 8, 2014.
(b) The amount includes the €30 thousand for participating in the Compensation Committee and €20 thousand for the Sustainability and Scenarios Committee.
(5)
Karina Litvack – Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders’ Meeting of May 8, 2014.
(b) The amount includes the €23 thousand for participating in the Control and Risk Committee, €20 thousand for participating in the Compensation Committee and €20 thousand for the Sustainability and Scenarios Committee.
(6)
Alessandro Lorenzi - Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders’ Meeting of May 8, 2014.
(b) The amount includes the €60 thousand for participating in the Control and Risk Committee and €20 thousand for the Compensation Committee.

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(7)
Diva Moriani – Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount includes the €12 thousand for participating in the Control and Risk Committee, €19 thousand for the Compensation Committee and €20 thousand for the Nomination Committee.

(8)
Fabrizio Pagani – Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount includes the €30 thousand for participating in the Sustainability and Scenarios Committee and €20 thousand for the Nomination Committee.

(9)
Alessandro Profumo – Director

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount includes the €20 thousand for partecipating in the Sustainability and Scenarios Committee and €20 thousand for the Nomination Committee.

(10)
Matteo Caratozzolo - Chairman of the Board of Statutory Auditors

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount related to the pro-rata remuneration for the office of Chairman of the Board of Statutory Auditors of TTPC (€32.1 thousand) and of Eni Adfin (€13.9 thousand).

(11)
Paola Camagni - Statutory Auditor

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount related to the pro-rata remuneration for the office of Chairman of the Board of Statutory Auditors of Eni East Africa (€18 thousand) and Auditor of Syndial (€12 thousand).

(12)
Alberto Falini - Statutory Auditor

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount related to the pro-rata remuneration for the office of Chairman of the Board of Statutory Auditors of Eni Timor Leste (€12.9 thousand) and Auditor of TTPC (€21.2 thousand).

(13)
Marco Lacchini - Statutory Auditor

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount related to the pro-rata remuneration for the office of Chairman of the Board of Statutory Auditors of SOM (€20.3 thousand) and Auditor of Eni East Africa (€12 thousand).

(14)
Marco Seracini - Statutory Auditor

(a) The amount corresponds to the fixed annual remuneration set by the Shareholders' Meeting of May 8, 2014.
(b) The amount related to the pro-rata remuneration for the office of Chairman of the Board of Statutory Auditors of Ing. Luigi Conti Vecchi (€18.2 thousand) and Auditor of Eni Adfin (€9.2 thousand).

(15)
Other Managers with strategic responsibilities

(a) The amount of €8,595 thousand for Gross Annual Salary is supplemented by the indemnities owed for the transfers performed, in Italy and abroad, in line with the provisions of the relevant national collective labour agreement for senior managers and with the Company's additional agreements as well as other indemnities related to the employment contract for a total amount of €851 thousand.
(b) The amount includes the payment of €3,170 thousand relating to the deferred and long-term monetary incentives assigned in 2013 and the pro-rata amounts of the Long-Term Incentive Plans (DMI and LTMI) paid upon consensual employment contract resolution, for the vesting period expired as defined in the respective Plan Regulations.
(c) The amount includes the taxable value of insurance and welfare coverage, complementary pensions, the car for business and personal use.
(d) Amounts due 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.
(e) The amount includes the severance indemnity and early retirement incentives paid in relation to the termination of the employment, to which €1,044 thousand is added for the non-competition clauses payable by 2017 at the expiry of the related validity period, subject to the obligations being fulfilled.

OTHER INFORMATION

Accrued compensation

Total compensation accrued in the year 2016 pertaining to all the Board members amounted to €7.1 million; it amounted to €0.738 million in the case of the Statutory Auditors. Such amounts include, in addition to each item of emolument reported in the table above, amounts accrued in the year for pension benefits, social security contributions and other elements of the remuneration associated with roles performed, which represent a cost for the Company.
For the year ended December 31, 2016, remuneration of persons in key positions in planning, direction and control functions of Eni Group companies, including executive and non-executive Directors, and other Managers with strategic responsibilities (with reference to all those individuals who, during the course of the 2016 period, filled said roles, even if only for a fraction of the year) amounted to €44 million and was accrued in Eni's Consolidated Financial Statements for the year ended December 31, 2016. The breakdown is as follow:

	2016
	(€ million)
Fees and salaries	26
Post-employment benefits	2
Other long-term benefits	12
Indemnity upon termination of the office	4
	44

The above amounts include salaries, fees for attending meetings, lump-sum amounts paid in lieu of expense reimbursements, stock-based compensation and other deferred incentive bonuses, health and pension contributions and amounts accrued to the reserve for employee termination indemnities, which is used to pay severance pay, as required by Italian law to employees upon termination of employment. The members of the Board of Directors in their capacity as such are not entitled to receive such severance pay.

As of December 31, 2016, the total amount accrued to the reserve for employee termination indemnities with respect to Chief Executive Officer and General Manager, Chief Operating Officers and other Managers with strategic responsibilities (with reference to the employed ones who, during the course of the 2016 period, filled said roles, even if only for a fraction of the year), was €1,706 thousand.

Name		(€ thousand)
Claudio Descalzi	Chief Executive Officer	352
Senior Managers (a)		1,353
		1,706

(a)
No. 18 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"). On July 9, 2015, the Italian Corporate Governance Committee approved a few amendments to the Corporate Governance Code. At its Meeting held on February 25, 2016, the Board adopted the new recommendations of the Code, acknowledging that Eni's Corporate Governance model was already broadly compliant with the new recommendations.

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 May 9, 2014, 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 attribute 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

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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 May 9, 2014, 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 Company 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 Board7, 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 May 9, 2014 and, after an investigation by the Nomination Committee, at its meeting of February 17, 2015, the Board of Directors determined that Chairman Marcegaglia and Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Zingales8 satisfy the independence requirements established by law, as referenced in Eni's By-laws. Furthermore, Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Zingales 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.

On July 29, 2015, the Eni Board of Directors appointed Alessandro Profumo to replace Luigi Zingales, who resigned on July 2, 2015. The Board of Directors, following an investigation performed by the Nomination Committee, on the basis of declarations made by Profumo and information available to the Company, ascertained that Profumo was independent according to law and the Corporate Governance Code. With reference to the marital relationship of Profumo with an employee of the Company, the Board resolved that this relationship does not compromise the independence requirements requested by the Corporate Governance Code, on account of Profumo's ethical and

professional integrity and his international reputation and taking into account the fact that his spouse is employed at a foundation, which is independent of Eni SpA9.
On February 25, 2016, and most recently on February 28, 2017, on the basis of statements made by the Directors and other information available to the Company, after an investigation by the Nomination Committee, the Board of Directors determined that Chairman Marcegaglia and Directors Gemma, Guindani, Litvack, Lorenzi, Moriani and Profumo satisfy the independence requirements established by law, as referenced in Eni's By-laws. Furthermore, Directors Gemma, Guindani, Litvack, Lorenzi, Moriani

(7)
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.

(8)
Luigi Zingales resigned from the Board of Directors on July 2, 2015.

(9)
On May 26, 2016, the Board of Directors, after an investigation by the Nomination Committee, on the basis of declarations made by Profumo and information available to the Company, verified that Profumo - confirmed by the Shareholders' Meeting on May 12, 2016 - was independent in accordance with law and the Corporate Governance Code, confirming the previous assessments.

and Profumo have been deemed independent by the Board pursuant to the criteria and parameters recommended by the Corporate Governance Code. The Board confirmed the independence requirements of Director Profumo on the basis of the aforementioned reasons. 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, are not significant for the purpose of assessing the independence of the Director himself, having regard to the nature and the amounts of these relationships.

The Board of Statutory Auditors ascertained that the Board of Directors correctly applied the assessment criteria and procedures for evaluating 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.

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 Compensation 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 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 Compensation Committee meetings upon the invitation of its Chairman, except when the meetings are examining proposals regarding their remuneration.

The Board Secretary and Corporate Governance Counsel coordinates the secretaries of the Board Committees, receiving at this end information on 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, Compensation Committee, Nomination Committee and Sustainability and Scenarios Committee were appointed by the Board of Directors on May 9, 2014, except for Director Profumo, appointed by the Board of Directors as a member of Nomination Committee and

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Sustainability and Scenarios Committee on September 17, 2015, and Director Diva Moriani, who was appointed as a member of the Control and Risk Committee on September 15, 2016, replacing Director Karina Litvack10; Director Diva Moriani left the Compensation Committee on December 22, 2016.

Compensation Committee

Members: Pietro A. Guindani (Chairman), Karina Litvack, Alessandro Lorenzi11.

The Compensation 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. In particular, at his appointment, the Director Guindani was identified by the Board as the member with "adequate knowledge and experience in finance or remuneration policies" as recommended by the Corporate Governance Code.

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: a) submits to the Board of Directors for its approval the Remuneration Report and, in particular, the Remuneration Policy for Directors and Managers with strategic responsibilities to be presented to the Shareholders' Meeting called to approve the financial statements, as provided for by applicable law; b) presents proposals for the remuneration of the Chairman of the Board and the Chief Executive Officer, covering the various forms of compensation and benefits awarded; c) presents proposals for the remuneration of members of the Board's internal committees; d) examines the CEO's indications and presents proposals for: (i) general criteria for the compensation of Managers with strategic responsibilities; (ii) annual and long-term incentive plans, including equity-based plans; and (iii) establishing performance targets and assessing results for performance plans in connection with the determination of the variable portion of the compensation for Directors with delegated powers and with the implementation of incentive plans; e) monitors the execution of Board resolutions regarding remuneration matters; f) periodically evaluates the adequacy, overall consistency and actual implementation of the adopted policy, as described in letter a) above, formulating proposals on the topic for the Board of Directors; g) performs the tasks required under the Company's procedures for handling related party transactions; h) 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, at least once every six months and no later than the deadline for the approval of the annual Financial Statements and the semi-annual financial report, on its activities at the Board Meeting indicated by the Chairman of the Board of Directors; and i) reports through its Chairman or another Committee member designated by the Chairman on its operational procedures to the Shareholders' Meeting called to approve the Financial Statements.

During 2016, the Compensation Committee met a total of nine times, with an average attendance of 94,4% of its members and an average duration of 3 hours and 13 minutes. All the Committee meetings were attended by at least one member of the Board of Statutory Auditors.

Earlier in the year, the Committee focused its activities in particular on the following topics: (i) periodic assessment of the Remuneration Policy implemented in 2015, also for the purpose of defining the proposed Policy Guidelines for 2016; (ii) review of 2015 corporate performance linked to the implementation of annual and long-term incentive plans, in accordance with a "variation analysis methodology" approved by the Committee in order to neutralize the positive or negative impact of exogenous factors, to allow an unbiased assessment of the performance levels achieved; (iii) definition of the 2016 performance targets related to the variable incentive plans, with the introduction of a new metric in the Annual Incentive Plan, enhancing exploration resources as a fundamental asset in order to preserve the sustainability of the Company's future results; (iv) definition of the proposals for the implementation of the Deferred Monetary Incentive Plan for the Chief Executive Officer and General Manager as well other senior executives; (v) review of the 2016 Eni Remuneration report; (vi)) review of the outcome of the first cycle of engagement conducted with main institutional investors, in order to maximize shareholder consensus on the 2016 Remuneration Policy, as well as of voting projections produced with the support of an international consultant.

(10)

On July 28, 2016, Eni's Board of Directors approved the replacement of Director Karina Litvack with another Director - identified by the Board itself in Director Diva Moriani on September 15, 2016 - in the Control and Risk Committee (CRC) in light of the ongoing investigations related to alleged conspiracy against the Company, reported also by the press. The board has taken this decision only to safeguard the Company from the risks of possible conflicts of interest until the closing of the investigation, remaining the presumption that Director Litvack has not been involved in the facts under investigations.

(11)
Director Diva Moriani left the Compensation Committee on December 22, 2016

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In the second part of the year the Committee primarily analyzed the results of the 2016 Shareholder's Meeting season, regarding the Eni Remuneration Report, the main Italian and European listed companies as well as companies in the peer group of reference. Among other main activities, the Committee also: (i) finalised the proposal concerning the fulfilment (2016 award) of the Long Term Incentive Plan for the Chief Executive Officer and General Manager and other critical management personnel; (ii) initiated the examination of the 2017 Remuneration Policy Guidelines, developing in particular, over the course of a number of meetings, a proposal for the revision of the variable incentive system applicable to the Chief Executive Officer and General Manager as well as Managers with Strategic Responsibilities, with the goal of further strengthening the alignment between the action of management and shareholder interests; (iii) approved the annual engagement plan prepared by the competent company functions and was informed of the findings of the first cycle of meetings held with the main proxy advisors, in implementation of the engagement plan for 2017.

The composition and appointment, as well as the duties and operating procedures, of the Committee are governed by the rules approved by the Board of Directors on July 30, 2014, and most recently amended on September 15, 2016, available to the public on the Company's website.

Control and Risk Committee

Members: Alessandro Lorenzi (Chairman), Andrea Gemma, Diva Moriani[12].

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[13] who possess the necessary expertise consistent with the duties they are required to perform[14].

In particular, at their appointment, the Directors Lorenzi 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 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

(12)
On September 15, 2016, Eni's Board of Directors appointed Diva Moriani as member of the Control and Risk Committee in place of Director Karina Litvack, following the replacement approved by the Board of Directors on July 28, 2016.

(13)

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.

(14)
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.

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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.

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Furthermore, the Committee oversees the activities of the Legal Affairs Department in case of judicial inquiries, carried out in Italy and/or abroad, in relation to which 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, have received a notice of investigation 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 on July 30, 2014 and amended on April 7, 2016, available to the public at the Company’s website.
Nomination Committee
Members: Andrea Gemma (Chairman), Diva Moriani, Fabrizio Pagani and Alessandro Profumo.
The Nomination Committee is made up of non-executive Directors, a majority of whom are independent.
The Committee provides the Board of Directors with recommendations and advice. In particular, the Committee: a) assists the Board of Directors in formulating any criteria for the appointment of persons indicated in the following letter and of 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, whose appointment fall under the Boards’ responsibility and oversees the associated succession plans. Where possible and appropriate, in relation to the shareholding structure, the Committee proposes to the Board of Directors the succession plan for the Chief Executive Officer; c) acting upon proposal of the Chief Executive Officer, examines and evaluates criteria governing the succession plan for the Company’s key management personnel; d) proposes candidates to serve as Directors on 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 on the minimum number of independent Directors and of 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 recommendation 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 sentence, 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 to be submitted 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; and 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 financial statements and of the 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 composition, appointment, duties and operational procedures of the Nomination Committee are governed by rules approved by the Board of Directors on July 30, 2014, and amended on April 7, 2016, available to the public at the Company’s website.

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Sustainability and Scenarios Committee

Members: Fabrizio Pagani (Chairman), Andrea Gemma, Pietro A. Guindani, Karina Litvack and Alessandro Profumo.
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: the health, well-being and safety of people and communities; the protection of rights; local development; access to energy, energy sustainability and climate change; the 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 May 8, 2014 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, 2016.

Name	Position	Year first appointed to Board of Statutory Auditors
Matteo Caratozzolo	Chairman	2014
Paola Camagni	Auditor	2014
Alberto Falini	Auditor	2014
Marco Lacchini	Auditor	2014
Marco Seracini	Auditor	2014
Stefania Bettoni	Alternate	2014
Mauro Lonardo	Alternate	2014

Paola Camagni, Alberto Falini, Marco Seracini and Stefania Bettoni (Alternate) were candidates listed in the slate presented by the Ministry of the Economy and Finance; Matteo Caratozzolo (Chairman), Marco Lacchini and Mauro Lonardo (Alternate) were candidates listed in the slate presented by non-controlling shareholders (institutional investors).

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, which were applied for the first time in the elections of the Board of Directors and the Board of Statutory Auditors at the Shareholders' Meeting held on May 8, 2014, one Statutory Auditor and one Alternate Statutory Auditor were drawn from the less represented gender. For the next two elections, one third of the statutory auditors will be 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.

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

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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 force as of December 31, 2016) in its role as the "internal control and financial auditing committee" the Board of Statutory Auditors oversees the following: (a) the financial reporting process; (b) the efficacy of internal control, internal audit (where applicable) and risk management systems; (c) the auditing of the annual financial statements and Consolidated Financial Statements; and (d) the independence of the external auditor or the Audit Firm, in particular with regard to the provision of non-audit services to the entity subject to financial auditing.

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).

As already set forth in the Consolidated Law on Financial Intermediation and currently regulated by Article 13 of Legislative Decree No. 39/2010, the Board of Statutory Auditors submits a reasoned opinion to the Shareholders' Meeting on the selection of the external auditors and the determination of the associated fees.

As from 2017 the above tasks provided for by the Legislative Decree. no. 39/2010, have been updated by Legislative Decree no. 135/ 2016, to comply with European Directive no 56/2014.

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, and lastly on May 28, 2014, the Board of Statutory Auditors approved the internal rules concerning its performance of the duties assigned to it under that U.S. legislation, the text of which is available on Eni's website15.

The key functions performed by the Board of Statutory Auditors acting as an audit committee as provided for by U.S. SEC rules are as follows:

- 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;

- making recommendations to the Board of Directors on the resolution of disagreements between management and the auditor regarding financial reporting;

- approving 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;

-

approving the procedures for the pre-approval of specifically identified admissible non-audit services and examining the disclosures on the execution of the authorized services;

- evaluating requests to use the external auditor firm engaged to perform audit services for admissible non-audit services and providing its opinion to the Board of Directors;

- 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

(15)
These internal rules will be subject to revision and possible updating to take into account the aforementioned regulatory changes.

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;

- examining reports from the CEO and the CFO concerning 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

- examining reports from the CEO and the CFO concerning 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 October 27, 2016, ratified the updating of Model 231 to incorporate a number of legislative changes in the environmental crimes provided for by Law no. 68/ 2015 ("eco-crimes").

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.

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.

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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 Ernst & Young SpA for the financial years 2010-2018.

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 is 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. The Magistrate of the Court attends the meetings of the Board of

Employees

As of December 31, 2016, Eni had a total of 33,536 employees, with a decrease of 660 employees, or down by 1.9% from December 31, 2015, which mainly reflects a decrease of 690 employees working outside Italy.

Employees at year end

	2014 (1)	2015 (1)	2016
	(number)		
Exploration & Production	12,777	12,821	12,494
Gas & Power	4,561	4,484	4,261
Refining & Marketing and Chemicals	11,884	10,995	10,858
Corporate and Other activities	5,624	5,896	5,922
	34,846	34,196	33,536

(1)
Excluding the operating segment E&C divested in January 2016.

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The table below sets forth Eni's employees as of December 31, 2014, 2015 and 2016 in Italy and outside Italy:

		2014 (1)	2015 (1)	2016
		(number)		
Exploration & Production	Italy	4,534	4,572	4,608
	Outside Italy	8,243	8,249	7,886
		12,777	12,821	12,494
Gas & Power	Italy	2,067	2,023	2,032
	Outside Italy	2,494	2,461	2,229
		4,561	4,484	4,261
Refining & Marketing and Chemicals	Italy	9,286	8,635	8,577
	Outside Italy	2,598	2,360	2,281
		11,884	10,995	10,858
Corporate and other activities	Italy	5,320	5,650	5,693
	Outside Italy	304	246	229
		5,624	5,896	5,922
Total	Italy	21,207	20,880	20,910
	Outside Italy	13,639	13,316	12,626
		34,846	34,196	33,536
of which senior managers		1,074	1,061	1,036

(1)
Excluding the operating segment E&C divested in January 2016.

We seek to maintain constructive relationship with labor unions.

Share ownership

As of February 28, 2017, the cumulative number of shares owned by Eni's Directors, Statutory Auditors and Senior Managers was 303,091 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	87,447 (1)
Claudio Descalzi	CEO	39,455
Board of Statutory Auditors		5,000 (2)
Senior Managers		171,189 (3)

(1)
Of which No. 1,034 shares held under Asset Management, No. 7,143 shares held under Asset Management jointly

with a third person, and No. 45,000 shares held as naked owner jointly with a third person.

(2)
Shares held under Asset Management.

(3)
Of which No. 14,390 shares owned by spouses not legally separated and by underage children.

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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 February 28, 2017, 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 February 28, 2017 have notified that their holding either exceeds the threshold of 3% since March 18, 2016 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) or the previous threshold of 2% (in effect until March 17, 2016)1.

Title of class	Percent of class
People's Bank of China	2.102

Decree Law 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 February 28, 2017, there were 36,611,569 ADRs outstanding, each representing two Eni ordinary shares, corresponding to approximately 2.0% 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 non-consolidated subsidiaries and 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 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 47 of the Notes on Consolidated Financial Statements".

(1)
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%. See "Item 10 – Additional information – Shareholder ownership thresholds".

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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, Eni believes that the foregoing 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 38 of the Notes on Consolidated Financial Statements".

Dividends

Eni's future dividend policy, as well as 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 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 "Risk factors" set out in Item 3 and the oil price scenario adopted by management 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 2017, we confirm our commitment to pay a full cash dividend of €0.80 per share and, later on, to a progressive distribution policy in line with the achievement of our plans of underlying earnings and cash flow growth and the scenario evolution. For further information on the Company's dividend policy see "Item 5 – Management's Expectations of Operation."

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. For further details see "Item 3 – Risk factors" and the other planning assumptions and initiatives described in "Item 5 – Management's expectations of operations".

At the General Shareholders' Meeting scheduled on April 13, 2017, management intends to propose the distribution of a dividend of €0.80 per share for fiscal year 2016, of which €0.40 paid as interim dividend in September 2016.

Total cash outlay for the 2016 balance dividend is expected at approximately €1.4 billion (whereas €1.4 billion were distributed in September 2016) if the General Shareholders' Meeting approves the annual dividend.

Significant changes

See "Item 5 – Recent developments" for a discussion of significant events occurred after 2016 year end up to the latest practicable date.

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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. See "Item 3 – Key information – Exchange rates" regarding applicable exchange rates during the periods indicated below.

	MTA		New York Stock Exchange	
	High	Low	High	Low
	(Euro per share)		(U.S.$ per ADR)	
Year ended December 31,				
2012	18.700	15.250	49.440	36.850
2013	19.480	15.290	52.120	40.390
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
2015				
First quarter	16.680	13.370	37.690	31.960
Second quarter	17.430	15.720	39.290	34.940
Third quarter	16.210	13.140	35.610	30.300
Fourth quarter	15.730	13.240	36.020	29.280
2016				
First quarter	13.800	10.930	31.050	25.000
Second quarter	14.580	12.320	33.330	28.170
Third quarter	14.900	12.310	33.250	27.650
Fourth quarter	15.470	12.260	32.240	26.260
Month of				
September 2016	14.030	12.310	31.600	27.650
October 2016	13.770	12.890	30.170	28.940
November 2016	13.140	12.260	28.740	26.260
December 2016	15.470	13.540	32.240	28.650
January 2017	15.720	14.210	33.260	30.880
February 2017	14.580	14.120	31.260	30.070
March 2017 (through March 17, 2017)	15.270	14.470	32.250	30.780

Since January 18, 2012, the Bank of New York Mellon (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 February 28, 2017, there were 36,611,569 ADRs outstanding, representing 71,233,138 ordinary shares or approximately 2% of all Eni's shares outstanding, held by 105 holders of record (including the Depository Trust

Company) in the United States, 104 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
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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. Since June 1, 2009, the 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 the first largest component of the FTSE MIB, with a weighting of approximately 14%, as established by FTSE Russel after the quarterly rebalancing for FTSE MIB effective December 19, 2016.

Beginning from October 6, 2014, 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 Italian Securitized Derivatives Market (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 regulated market 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 February 13, 2017: (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 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 are MTA (shares, convertible bonds, pre-emptive rights, warrants and Funds), ETFplus (Exchange Traded Funds, Exchange Traded Commodities, Exchange Traded Notes and open-ended funds market), IDEM (index, stock and other derivatives market), SeDeX (covered warrants and certificates), MOT (bond market) and MIV (market for investment vehicles), as well as the admission to listing on and trading on these markets.

According to EU Markets in Financial Instruments Directive (No. 2004/39/EC) (MiFID) 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 or a bank which deals on own account by executing client orders outside a Regulated Market or a MTF. Outside Regulated Markets, block trading is also permitted for orders that meet certain minimum size requirements and must be notified to Consob and Borsa Italiana.

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Following the transposition in Italy of Directive No. 2014/65/EU ("MiFID II"), which is due to be implemented by 3 January 2018, Organized Trading Facilities ("OTFs") will be 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. The implementation of the MiFID II and entry into force of the Regulation (EU) No. 600/2014 ("MiFIR") will entail some additional changes to the regulatory framework currently applicable to Regulated Markets, MTFs and Systematic Internalisers.

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 reserved to banks and investment firms ("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.

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 ("EMIR") and the Regulation (EU) No. 909/2014 ("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.

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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 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

(1)
The Board of Directors modified this Management System Guideline on January 19, 2012.

(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.

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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 explain their potential interests related to Eni and its subsidiaries, and in any case they inform the CEO (or the Chairman, in the case the CEO holds an interest) about individual transactions that Eni intends to carry out in which they have an interest; the CEO (or Chairman) will then inform the other Directors and the Board of Statutory Auditors.

Compensation

Directors' compensation shall be determined by the Shareholders' Meeting, as required by Italian law, while the compensation of Directors assigned particular duties 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 Compensation Committee, after consultation with the Board of Statutory Auditors (for more details about the compensation policy in 2016, see "Item 6 – Compensation").

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.

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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 25, 2017, 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

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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 33 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.

(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.

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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, modified Italian legislation governing the special powers of the Italian State to comply with European rules4.

The new special powers no longer apply to specific State-controlled companies, identified by name, but 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.

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.

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.

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

(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.

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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 Finance5 and the Consob Regulation6, any direct or indirect holding in the voting shares of an Italian listed company in excess of 3%7 (until March 17, 2016, the threshold was 2%), 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 criteria8. 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 investments9.

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% (until March 17, 2016, the threshold was 2%) 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.

(5)
Legislative Decree No. 58 of February 24, 1998, with specific reference to Articles 120-122.

(6)
Article 117 of Consob Decision No. 11971/1999 and subsequent amendments.

(7)
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.

(8)
Article 118 of Consob Decision No. 11971/1999 and subsequent amendments.

(9)
Article 119 of Consob Decision No. 11971/1999 and subsequent amendments.

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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, in accordance with Law No. 287 of October 10, 1990, any merger or acquisition of sole or joint control over a company or any change of control over a company that would create or strengthen a dominant position in the domestic market in a manner that eliminates or significantly reduces competition is prohibited and mergers and acquisition of specified dimension must be subject to the prior authorization of the Italian Antitrust Authority10. However, if the merging parties or the acquiring party and the company to be acquired operate in more than one EU Member State and/or outside Europe and exceed certain thresholds (e.g. turnover, asset value or market share thresholds), the antitrust approval for the merger and/or acquisition can fall under the jurisdiction of the European Commission or the EU Members States and/or other Competition Authorities outside Europe.

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.

(10)
Autorità garante per la concorrenza e il mercato (AGCM - www.agcm.it).

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Exchange controls

There are no exchange controls in Italy. Residents and non-residents in Italy may carry out any investments, divestments and other transactions that entail a transfer of assets to or from Italy, subject only to the reporting, record-keeping and disclosure requirements described below. In particular, residents of Italy may hold foreign currency and foreign securities of any kind, within and outside Italy, while non-residents may invest in Italian securities without restriction and may export from Italy cash, instruments of credit or payment and securities, whether in foreign currency or euro, representing interest, dividends, other asset distributions and the proceeds of dispositions. Updated reporting and record-keeping requirements are contained in the Italian legislation which implements an EU directive regarding the free movement of capital. Such legislation requires that transfers into or out of Italy of cash or securities in excess of €12,500 be reported in writing to the relevant authority (Ministry of Economy and Finance) by residents or non-residents that effect such transfers directly, or by banks, securities dealers or Poste Italiane SpA (Italian Mail) that effect such transactions on their behalf. In addition, banks, securities dealers or Poste Italiane SpA effecting such transactions on behalf of residents or non-residents of Italy are required to maintain records of such transactions for five years. These records may be inspected at any time by Italian Tax and Judicial Authorities. Non-compliance with these reporting and record-keeping requirements may result in administrative fines or, in the case of false reporting and in certain cases of incomplete reporting, criminal penalties.

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 received by Italian resident individuals in relation to interest exceeding 2% of the voting rights or 5% of the share capital ("substantial interest") are included in the taxable income subject to personal income tax to the extent of 49.72% of their amount. Article 1, paragraph 64 of Law No. 208 of December 28, 2015 ("Italian Budget Law for the 2016") provides that the percentages of the dividends relevant for the taxable income will be changed by a Decree of the Minister of Economy and Finance, in proportion to the IRES rate reduction to 24% as provided by Article 1, paragraph 61 of the aforementioned Italian Budget Law for the 2016.Personal income tax applies at progressive rates ranging from 23% to 43% plus local surtaxes. Dividends received by Italian resident individuals in relation to non-substantial interest not related to the conduct of a business 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. If the non-substantial interest is related to the conduct of a business, dividends are included in the taxable business income for 49.72% of their amount. Article 1, paragraph 64 of the Italian Budget Law for the 2016 provides that the percentages of the dividends and capital gains relevant for the taxable income will be changed by a Decree of the Minister of Economy and Finance, in proportion to the IRES rate reduction to 24% as provided by Article 1, paragraph 61 of the aforementioned Italian Budget Law for the 2016. The change of tax rate does not apply to the entities referred to into Article 5 of Presidential Decree 22 December 1986 No. 917.

Despite the above statement, dividends are included in the taxable income at 40% to the extent they relate to undistributed profit of 2007 and previous years.

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

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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 (12.5% as regards income from government bonds).

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 1.375% 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 Norway. Because corporate tax rate has been decreased to 24%, from the 1st of January 2017, the above mentioned dividends on 2017 income are subject to a 1,2% withholding tax.

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.

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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 upon the sale of a substantial interest are included in the taxable base subject to personal income tax for 49.72% of their amount. Article 1, paragraph 64 of the Italian Budget Law for the 2016 provides that the percentages of the capital gains relevant for the taxable income will be changed by a Decree of the Minister of Economy and Finance, in proportion to the IRES rate reduction to 24% as provided by Article 1, paragraph 61, of the aforementioned Italian Budget Law for the 2016. Gains realized upon the sale of non-substantial interest is subject to a substitute tax at a 26% rate.

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).

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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 Eni SpA's Shares, 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

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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 as 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, depending on your circumstances,be either "passive" or "general" 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, unless a U.S. Holder elects to be taxed annually on a mark-to-market basis with respect to the Shares or ADSs, gain realized on the sale or other disposition of your Shares or ADSs would in general not be treated as capital gain. Instead, if classified as a U.S. Holder,

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one 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. SEC at the U.S. SEC's public reference room located at 100 F Street NE, Washington, DC 20549, USA.

You may also call the U.S. SEC at +1 800-SEC-0330 or log on to www.sec.gov.

It is also possible to read and copy documents referred to in this Annual Report on Form 20-F at the New York Stock Exchange, 20 Broad Street, 17th floor, New York, USA.

Item 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the possibility that the exposure to fluctuations 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. 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 downstream gas and refining and marketing businesses and petrochemical operations 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 as in the case of gas prices. 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

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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 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). 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. 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 value, direct or caused by fluctuation of interest rates, inflation rates, foreign exchange rates or credit risk, of different assets under Eni control or that Eni will have under its controls in the normal course of business; 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 entailcounterparty 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.

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- 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 is an asset the higher is its extrinsic value that can be normally quantified as an option premium, linked to the price of an underlying commodity, volatility, time, interest rate. In order to protect the value of asset flexibility a business unit may transfer to a central entity part or the whole of 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 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 term 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. 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. 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 38 of the Notes on Consolidated Financial Statements" for a qualitative and quantitative discussion of the Company's exposure to market risks. Please also refer to "Item 18 – notes 15, 23, 28, 33 and 34 of the

Notes on Consolidated Financial Statements" for details of the different derivatives owned by the Company in these markets.

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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. Since January 18, 2012, Eni's ADRs are issued, cancelled and exchanged at the office of Bank of New York Mellon, as depositary (the "Depositary") under the Deposit Agreement between Eni, the Depositary and the holders of ADRs.

Computershare is the transfer agent for the Eni SpA ADR program.

Société Générale Securities Services SpA and UniCredit SpA are the custodians (the "Custodian") on behalf of the holders of Eni's ADRs, and their principal offices are located in Milan, Italy.

Fees and charges paid by ADR holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting on their behalf. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of distributable property to pay the fees.

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The table below sets forth all fees and charges that a holder of Eni's ADRs may have to pay, either directly or indirectly, to Bank of New York Mellon, as Depositary.

Type of service	Amount of fees or charges(1)	Depositary actions
(a) Depositing or substituting the underlying shares	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Each person to whom ADRs are issued against deposits of shares, including deposits and issuances in respect of: • Share distributions, stock split, rights, merger. • Exchange of securities or any other transaction or event or other distribution affecting the ADSs or the Deposited Securities.
(b) Selling or exercising rights	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Distribution or sale of securities, the fee being in an amount equal to the fee for the execution and delivery of ADSs which would have been charged as a result of the deposit of such securities.
(c) Withdrawing an underlying security	$5.00 (or less) for each 100 ADSs (or portion of 100 ADSs)	Acceptance of ADRs surrendered for withdrawal of deposited securities.
(d) Transferring, splitting or grouping receipts	Registration or transfer fees	Transfers, combining or grouping of depositary receipts.
(e) Expenses of the depositary	Varied charges	Expenses incurred on behalf of holders in connection with: • The Depositary's or its custodian's compliance with applicable law, rule or regulation. • Stock transfer or other taxes and other governmental charges. • Cable, telex, facsimile transmission/ delivery. • Expenses of the Depositary in connection with the conversion of foreign currency into U.S. dollars (which are paid out of such foreign currency). • Any other charge payable by Depositary or its agents.
(f) Distribution of cash	$0.02 (or less) per ADS	Any cash distribution to ADS registered holders.
(g)		Depositary services.

Depositary services	$0.02 (or less) per ADS per calendar year

(1)
All fees and charges are paid by ADR holders to Bank of New York Mellon as Depositary and Transfer agent.

Fees and payments made by the Depositary to the issuer
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 2016, as agreed in the Deposit Agreement with the previous depositary bank, JPMorgan Chase Bank of New York, and subsequent amendments, the Depositary will reimburse to Eni up to US$2,200,000 in connection with above mentioned expenditures.

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Expenses waived or paid directly to third parties by the Depositary

The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of US$189,419.31 for the year ended December 31, 2016.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended December 31, 2016
	(US$)
BNY Mellon products and services	120,000.00
BNY Mellon related to servicing registered shareholders	650.90
BNY Mellon paid to third-party vendors(1)	68,768.41
Total	189,419.31

(1)
Includes payments for AGM and related ADR Program services.

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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.

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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, 2016.
The effectiveness of the Company's internal control over financial reporting as of December 31, 2016, has been audited by Reconta Ernst & Young 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": Matteo Caratozzolo, who is the Chairman of the Board, Paola Camagni, Alberto Falini, Marco Lacchini 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 Eni's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. Eni published its Code of Ethics on Eni's website. It is accessible at www.eni.com, under the section Corporate 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

Reconta Ernst & Young SpA has served as Eni principal independent public auditor for fiscal years 2016 and 2015 for which audited Consolidated Financial Statements appear in this Annual Report on Form 20-F.

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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 Reconta Ernst & Young SpA and its respective member firms, for the years ended December 31, 2016 and 2015, respectively:

	Year ended December 31,	
	2015	2016
	(€ thousand)	
Audit fees	33,752	21,433
Audit-related fees	1,138	1,874
Tax fees	3	
All other fees		
Total	34,893	23,307

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 2016, 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.

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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 20-F filing for the year ended December 31, 2016.

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 their

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judgment. 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 2016, Eni's independent Directors had numerous opportunities to meet, formally and 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 Code1. On

(1)
The Committee is currently made up of four Directors, three of whom are independent.

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May 9, 2014, the Board of Directors of Eni established the Nomination Committee, chaired by Andrea Gemma (independent Director) and composed of Diva Moriani (independent Director), Fabrizio Pagani (non-executive Director) and Luigi Zingales (independent Director). On September 17, 2015, the Board appointed Director Alessandro Profumo (independent Director) as a member of the Committee, replacing Luigi Zingales who resigned from the Board on July 2, 2015. Further details on this Committee are reported in the Item 6.

Compensation Committee

NYSE standards. U.S. listed companies must have a Compensation Committee composed entirely of independent Directors who must satisfy the independence requirements provided for its members. The Compensation Committee must have a written charter that addresses the Committee's purpose and responsibilities within the limit set forth by the listing rules. The Compensation 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 Compensation 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 Compensation Committee is currently chaired by Director Pietro A. Guindani. The other members include directors Karina A. Litvack and Alessandro Lorenzi2. 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 October 27, 2016, ratified the updating of Model 231 to incorporate a number of legislative changes provided for by law No. 68/2015 ("eco-crime"). The CEO is supported in this activity by 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

(2)

Director Diva Moriani left the Compensation Committee on December 22, 2016.

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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.

Item 16H. Mine safety disclosure

Not applicable since Eni does not engage in mining operations.

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PART III

Item 17. FINANCIAL STATEMENTS

Not applicable.

Item 18. FINANCIAL STATEMENTS

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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) Report of DeGolyer and MacNaughton

15.a(ii) Report of Ryder Scott Co

15.a(iii) Gaffney, Cline & Associates

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Eni S.p.A.

We have audited the accompanying consolidated balance sheets of Eni S.p.A. as of December 31, 2016 and 2015, and the related consolidated profit and loss account 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, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Eni S.p.A. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

As discussed in Note 5 to the consolidated financial statements, the Company has elected to change its method of accounting for the oil & gas exploration and production activities to the “Successful Efforts Method”. The Company applied this change in accounting principle retrospectively to all prior periods presented.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Eni S.p.A.’s internal control over financial reporting as of December 31, 2016, 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 March 22, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young S.p.A.

Rome, Italy

March 22, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Eni S.p.A,

We have audited Eni S.p.A.'s internal control over financial reporting as of December 31, 2016, 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). Eni S.p.A.'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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Eni S.p.A. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Eni S.p.A. as of December 31, 2016 and 2015, and the related consolidated profit and loss account 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, 2016 and our report dated March 22, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young S.p.A.

Rome, Italy

March 22, 2017

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CONSOLIDATED BALANCE SHEET

(euro million)

January 1, 2015(a)				December 31, 2015(a)		December 31, 2016	
Total amount	of which with related parties		Note	Total amount	of which with related parties	Total amount	of which with related parties
		ASSETS					
		Current assets					
6,614		Cash and cash equivalents	(8)	5,209		5,674	
5,024		Financial assets held for trading	(9)	5,028		6,166	
257		Financial assets available for sale	(10)	282		238	
28,601	1,973	Trade and other receivables	(11)	21,640	1,985	17,593	1,100
7,555		Inventories	(12)	4,579		4,637	
762		Current tax assets	(13)	360		383	
1,209		Other current tax assets	(14)	630		689	
4,385	43	Other current assets	(15) (34)	3,642	50	2,591	57
54,407				41,370		37,971	
		Non-current assets					
75,991		Property, plant and equipment	(16)	68,005		70,793	
1,581		Inventory – compulsory stock	(17)	909		1,184	
4,420		Intangible assets	(18)	3,034		3,269	
3,172		Equity-accounted investments	(20)	2,853		4,040	
2,015		Other investments	(20)	660		276	
1,042	259	Other financial assets	(21)	1,026	396	1,860	1,349
4,509		Deferred tax assets	(22)	3,853		3,790	
2,773	12	Other non-current assets	(23) (34)	1,758	10	1,348	13
95,503				82,098		86,560	
456		Discontinued operations and assets held for sale	(35)	15,533	308	14	
150,366		TOTAL ASSETS		139,001		124,545	
		LIABILITIES AND SHAREHOLDERS' EQUITY					
		Current liabilities					
2,716	181	Short-term debt	(24)	5,720	208	3,396	191
3,859		Current portion of long-term debt	(29)	2,676		3,279	
23,703	1,954	Trade and other payables	(25)	14,942	1,544	16,703	2,289

534		Income tax payable	(26)	431		426	
1,873		Other tax payable	(27)	1,454		1,293	
4,489	58	Other current liabilities	(28) (34)	4,712	96	2,599	88
37,174				29,935		27,696	
		Non-current liabilities					
19,316		Long-term debt	(29)	19,397		20,564	
15,882		Provisions for contingencies	(30)	15,375		13,896	
1,313		Provisions for employee benefits	(31)	1,123		868	
8,590		Deferred tax liabilities	(32)	7,425		6,667	
2,285	20	Other non-current liabilities	(33) (34)	1,852	23	1,768	23
47,386				45,172		43,763	
165		Discontinued operations and liabilities directly associated with assets held for sale	(35)	6,485	207		
84,725		TOTAL LIABILITIES		81,592		71,459	
		SHAREHOLDERS' EQUITY	(36)				
2,455		Non-controlling interest		1,916		49	
		Eni shareholders' equity					
4,005		Share capital		4,005		4,005	
(284)		Reserve related to cash flow hedging derivatives net of tax effect		(474)		189	
60,763		Other reserves		62,761		52,329	
(581)		Treasury shares		(581)		(581)	
(2,020)		Interim dividend		(1,440)		(1,441)	
1,303		Net profit (loss)		(8,778)		(1,464)	
63,186		Total Eni shareholders' equity		55,493		53,037	
65,641		TOTAL SHAREHOLDERS' EQUITY		57,409		53,086	
150,366		TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY		139,001		124,545	

(a)
Information on the restatement of comparative data in application of IAS 8 is reported in note 5 — Changes in accounting principles.

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CONSOLIDATED PROFIT AND LOSS ACCOUNT
(euro million except as otherwise stated)

	Note	2014(a) Total amount	of which with related parties	2015(a) Total amount	of which with related parties	2016 Total amount	of which with related parties
REVENUES	(39)						
Net sales from operations		98,218	1,497	72,286	1,342	55,762	1,238
Other income and revenues		1,079	69	1,252	69	931	74
		99,297		73,538		56,693	
OPERATING EXPENSES	(40)						
Purchases, services and other		77,404	7,143	56,848	6,882	44,124	8,212
Payroll and related costs		2,929	60	3,119	55	2,994	24
OTHER OPERATING (EXPENSE) INCOME	(40)	145	208	(485)	96	16	247
Depreciation and amortization	(40)	7,676		8,940		7,559	
Net Impairments/reversal	(40)	1,270		6,534		(475)	
Write-off of tangible and intangible assets	(40)	1,198		688		350	
OPERATING PROFIT (LOSS)		8,965		(3,076)		2,157	
FINANCE INCOME (EXPENSE)	(41)						
Finance income		5,701	46	8,635	83	5,850	157
Finance expense		(7,057)	(41)	(10,104)	(50)	(6,232)	(145)
Net Finance income from financial assets held for trading		24		3		(21)	
Derivatives financial instruments		165		160		(482)	27
		(1,167)		(1,306)		(885)	
INCOME (EXPENSE) FROM INVESTMENTS	(42)						
Share of profit (loss) from equity-accounted investments		110		(471)		(326)	
Other gain (loss) from investments		366		576		(54)	
		476		105		(380)	
		8,274		(4,277)		892	

PROFIT BEFORE INCOME TAXES						
Income taxes	(43)	(6,466)		(3,122)		(1,936)
Net profit (loss) for the year - Continuing operations		1,808		(7,399)		(1,044)
Net profit (loss) for the year - Discontinued operations	(35)	(949)	867	(1,974)	142	(413)
Net profit (loss) for the year		859		(9,373)		(1,457)
Attributable to Eni						
– continuing operations		1,720		(7,952)		(1,051)
– discontinued operations	(35)	(417)		(826)		(413)
		1,303		(8,778)		(1,464)
Attributable to non-controlling interest	(36)					
- continuing operations		88		553		7
- discontinued operations	(35)	(532)		(1,148)		
		(444)		(595)		7
Earnings per share attributable to Eni (€ per share)	(44)					
Basic		0.36		(2.44)		(0.41)
Diluted		0.36		(2.44)		(0.41)
Earnings per share attributable to Eni - Continuing operations (€ per share)	(44)					
Basic		0.48		(2.21)		(0.29)
Diluted		0.48		(2.21)		(0.29)

(a)
Information on the restatement of comparative data in application of IAS 8 is reported in note 5 — Changes in accounting principles.

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(euro million)

	Note	2014(a)	2015(a)	2016
Net profit		859	(9,373)	(1,457)
Other items of comprehensive income				
Items that are not reclassified to profit in later periods				
Remeasurements of defined benefit plans	(36)	(82)	36	16
Share of other comprehensive income on equity accounted entities in relation to remeasurements of defined benefit plans	(36)	3		
Tax effect related to other comprehensive income not to be reclassified to profit or loss in subsequent periods	(36)	22	(21)	(35)
		(57)	15	(19)
Items that may be reclassified to profit in later periods				
Currency translation differences	(36)	5,427	4,837	1,198
Change in the fair value of available-for-sale investments	(36)	(77)		
Change in the fair value of other available-for-sale financial instruments	(36)	7	(4)	(4)
Change in the fair value of cash flow hedging derivatives	(36)	(167)	(256)	883
Share of other comprehensive income on equity-accounted entities	(36)	4	(9)	32
Tax effect related to other comprehensive income to be reclassified to profit or loss in subsequent periods	(36)	30	66	(220)
		5,224	4,634	1,889
Total other items of comprehensive income		5,167	4,649	1,870
Total comprehensive income		6,026	(4,724)	413
Attributable to Eni				
- continuing operations		6,817	(3,416)	819
- discontinued operations	(35)	(390)	(779)	(413)
		6,427	(4,195)	406
Attributable to non-controlling interest				
- continuing operations		91	554	7
- discontinued operations	(35)	(492)	(1,083)	
		(401)	(529)	7

(a)
Information on the restatement of comparative data in application of IAS 8 is reported in note 5 — Changes in accounting principles.

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CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(euro million)

	Note	Eni shareholders' equity								
		Share capital	Legal reserve of Eni SpA	Reserve for treasury shares	Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	Reserve related to the fair value of available-for-sale financial instruments net of the tax effect	Reserve for defined benefit plans net of the tax effect	Other reserves	Cumulative currency translation differences	Treasury shares
Balance at December 31, 2013		4,005	959	6,201	(154)	81	(72)	296	(698)	(201)
Changes in accounting principles (SEM)										
Balance at January 1, 2014		4,005	959	6,201	(154)	81	(72)	296	(698)	(201)
Net profit (loss) for the year										
Other items of comprehensive income										
Items that are not reclassified to profit in later periods										
Remeasurements of defined benefit plans net of tax effect							(51)			
Share of "Other comprehensive income" on equity-accounted entities in relation to remeasurements of defined benefit plans net of							2			

tax effect			(49)		
Items that may be reclassified to profit in later periods					
Currency translation differences			(1)		5,137
Change and reversal of the fair value of investments net of tax effect		(76)			
Change and reversal of the fair value of other available-for-sale financial instruments net of tax effect		6			
Change and reversal the fair value of cash flow hedge derivatives net of tax effect	(130)				
Share of "Other comprehensive income" on equity-accounted entities				5	
	(130)	(70)	(1)	5	5,137
Total comprehensive income of the year	(130)	(70)	(50)	5	5,137
Transactions with shareholders					
Dividend distribution of Eni SpA (€0.55 per share in settlement of 2013 interim dividend of €0.55 per share)					

Interim dividend distribution of Eni SpA (€0.56 per share)										
Dividend distribution of other companies										
Allocation of 2013 net profit										
Acquisition of treasury shares										(380)
Payments and reimbursements by/to minority shareholders										
										(380)
Other changes in shareholders' equity										
Elimination of intercompany profit between companies with different Group interest										
Stock options expired										
Other changes								(94)		
								(94)		
Balance at December 31, 2014	(36)	4,005	959	6,201	(284)	11	(122)	207	4,439	(581)
Net profit (loss) for the year										
Other items of comprehensive income										
Items that are not reclassified to profit in later periods										
Remeasurements of defined benefit plans net of tax effect	(36)						14			
Reclassification of "Other	(35)						8			
	(36)									

comprehensive loss” related to discontinued operations				22		
Items that may be reclassified to profit in later periods						
Currency translation differences	(36)			(1)		4,722
Change and reversal of the fair value of other available-for-sale financial instruments net of tax effect	(36)		(3)			
Change and reversal the fair value of cash flow hedge derivatives net of tax effect	(36)	(194)				
Share of “Other comprehensive income” on equity-accounted entities	(36)				(9)	
Reclassification of “Other comprehensive income” related to discontinued operations	(35) (36)	4				(32)
		(190)	(3)	(1)	(9)	4,690
Total comprehensive income of the year		(190)	(3)	21	(9)	4,690
Transactions with shareholders						
Dividend distribution of Eni SpA (€0.56 per share in	(36)					

settlement of 2014 interim dividend of €0.56 per share)										
Interim dividend distribution of Eni SpA (€0.40 per share)	(36)									
Dividend distribution of other companies										
Allocation of 2014 net loss										
Payments and reimbursements by/to minority shareholders	(36)									
Other changes in shareholders' equity										
Elimination of intercompany profit between companies with different Group interest										
Exclusion from the scope of consolidation of non-significant companies and changes in non-controlling interests										
Reclassification of the reserve for treasury shares				(5,620)						
Other changes								(18)		
				(5,620)				(18)		
Balance at December 31, 2015	(36)	4,005	959	581	(474)	8	(101)	180	9,129	(581)

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CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (continued)
(euro million)

		Eni shareholders' equity									
	Note	Share capital	Legal reserve of Eni SpA	Reserve for treasury shares	Reserve related to the fair value of cash flow hedging derivatives net of the tax effect	Reserve related to the fair value of available-for-sale financial instruments net of the tax effect	Reserve for defined benefit plans net of the tax effect	Other reserves	Cumulative currency translation differences	Treasury shares	Reta earn
Balance at December 31, 2015	(36)	4,005	959	581	(474)	8	(101)	180	9,129	(581)	51
Net profit (loss) for the year											
Other items of comprehensive income											
Items that are not reclassified to profit in later periods											
Remeasurements of defined benefit plans net of tax effect	(36)						(19)				
							(19)				
Items that may be reclassified to profit in later periods											
Currency translation differences	(36)						8		1,190		
Change and reversal of the fair value of other available-for-sale	(36)					(4)					

financial instruments net of tax effect							
Change and reversal the fair value of cash flow hedge derivatives net of tax effect	(36)	663					
Share of "Other comprehensive income" on equity-accounted entities	(36)				32		
		663	(4)	8	32	1,190	
Total comprehensive income of the year		663	(4)	(11)	32	1,190	
Transactions with shareholders							
Dividend distribution of Eni SpA (€0.40 per share in settlement of 2015 interim dividend of €0.40 per share)	(36)						(1,
Interim dividend distribution of Eni SpA (€0.40 per share)	(36)						
Dividend distribution of other companies							
Allocation of 2015 net loss							(10
							(1
Other changes in shareholders' equity							
Exclusion from the scope of consolidation of Saipem group following the sale of the control							

Reclassification to profit and loss account of amounts previously recognized in other comprehensive income related to Saipem	(35)										(8)
Other changes								(1)			48
								(1)			40
Balance at December 31, 2016	(36)	4,005	959	581	189	4	(112)	211	10,319	(581)	40

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CONSOLIDATED STATEMENT OF CASH FLOWS
(euro million)

	Note	2014(a)	2015(a)	2016
Net profit (loss) of the year – Continuing operations		1,808	(7,399)	(1,044)
Adjustments to reconcile net profit to net cash provided by operating activities				
Depreciation and amortization	(40)	7,676	8,940	7,559
Net Impairments/reversal	(40)	1,270	6,534	(475)
Write-off of tangible and intangible assets	(40)	1,198	688	350
Share of (profit) loss of equity-accounted investments	(42)	(110)	471	326
Gain on disposal of assets, net		(224)	(577)	(48)
Dividend income	(42)	(385)	(402)	(143)
Interest income		(162)	(164)	(209)
Interest expense		681	659	645
Income taxes	(43)	6,466	3,122	1,936
Other changes		852	586	(9)
Changes in working capital:				
- inventories		1,620	1,638	(273)
- trade receivables		2,051	4,944	1,286
- trade payables		(1,669)	(2,342)	1,495
- provisions for contingencies		(234)	43	(1,043)
- other assets and liabilities		431	498	647
Cash flow from changes in working capital		2,199	4,781	2,112
Net change in the provisions for employee benefits		12	(3)	22
Dividends received		603	545	212
Interest received		107	81	160
Interest paid		(851)	(692)	(780)
Income taxes paid, net of tax receivables received		(6,671)	(4,295)	(2,941)
Net cash provided by operating activities – Continuing operations		14,469	12,875	7,673
Net cash provided by operating activities – Discontinued operations	(35)	273	(1,226)	
Net cash provided by operating activities		14,742	11,649	7,673
- of which with related parties	(47)	(3,203)	(3,966)	(3,749)
Investing activities:				
- tangible assets	(16)	(11,646)	(11,177)	(9,067)
- intangible assets	(18)	(226)	(125)	(113)
- consolidated subsidiaries and businesses net of cash and cash equivalent acquired	(37)	(36)		
- investments	(20)	(372)	(228)	(1,164)

- securities		(77)	(201)	(1,336)
- financing receivables		(1,289)	(1,103)	(1,208)
- change in payables in relation to investing activities and capitalized depreciation		669	(1,058)	(8)
Cash flow from investing activities		(12,977)	(13,892)	(12,896)
Disposals:				
- tangible assets		104	427	19
- intangible assets		1	32	
- consolidated subsidiaries and businesses net of cash and cash equivalent disposed of	(37)		73	(362)
- investments		3,579	1,726	508
- securities		57	18	20
- financing receivables		506	533	8,063
- change in receivables in relation to disposals		155	160	205
Cash flow from disposals		4,402	2,969	8,453
Net cash used in investing activities		(8,575)	(10,923)	(4,443)
- of which with related parties	(47)	(1,458)	(1,583)	3,752

(a)
Information on the restatement of comparative data in application of IAS 8 is reported in note 5 — Changes in accounting principles.

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CONSOLIDATED STATEMENT OF CASH FLOWS (continued)
(euro million)

	Note	2014 (a)	2015 (a)	2016
Increase in long-term financial debt	(29)	1,916	3,376	4,202
Repayments of long-term financial debt	(29)	(2,751)	(4,466)	(2,323)
Increase (decrease) in short-term financial debt	(24)	207	3,216	(2,645)
		(628)	2,126	(766)
Net capital contributions by non-controlling interest		1	1	
Dividends paid to Eni's shareholders		(4,006)	(3,457)	(2,881)
Dividends paid to non-controlling interest		(49)	(21)	(4)
Acquisition of treasury shares		(380)		
Net cash used in financing activities		(5,062)	(1,351)	(3,651)
- of which with related parties	(47)	(99)	13	(192)
Effect of change in consolidation (inclusion/ exclusion of significant/insignificant subsidiaries)		2	(13)	(5)
Effect of cash and cash equivalents pertaining to discontinued operations	(37)		(889)	889
Effect of exchange rate changes on cash and cash equivalents and other changes		76	122	2
Net cash flow of the year		1,183	(1,405)	465
Cash and cash equivalents - beginning of the year (excluding discontinued operations)	(8)	5,431	6,614	5,209
Cash and cash equivalents - end of the year (excluding discontinued operations)	(8)	6,614	5,209	5,674

(a)
Information on the restatement of comparative data in application of IAS 8 is reported in note 5 — Changes in accounting principles.

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Notes on Consolidated Financial Statements

1 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 requirements in IFRSs that apply. In particular, starting from January 1, 2016, Eni has adopted, on a voluntary basis, the so-called Successful Efforts Method (hereinafter also SEM) to recognize and measure costs related to exploration activities, in order to improve the comparability of Eni's results with those of the competitors, as well as to ensure financial reporting that is proper, reliable and consistent with the decision-making processes related to the evaluation of the exploration and production activities' results. The recognition and measurement criteria for the oil&gas exploration and production activities are indicated in the accounting policy for "Oil and natural gas exploration, appraisal, development and production expenditure"; the effects arising from the adoption of SEM are indicated in note 5 "Changes in accounting policies".

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 note 3 "Significant accounting policies".

The 2016 Consolidated Financial Statements included in the Annual Report on Form 20-F, approved by the Eni's Board of Directors on March 17, 2017, 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.

Amounts in the financial statements and in the notes are expressed in millions of euros (euro million).

2 Principles of consolidation

Subsidiaries

The Consolidated Financial Statements comprise the financial statements of the parent Company Eni SpA and those of its Italian and foreign 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. 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 revenues and other operating data (production, reserves, etc.) of the project, as well as the related obligations arising from the project, are recognized directly in the financial statements of the companies involved based on their own share. Some subsidiaries are not consolidated because they are immaterial, either individually or in the aggregate; this exclusion has not produced significant[2] effects on the Consolidated Financial Statements.

(1)
IFRSs include also International Accounting Standards (IAS), currently effective, as well as the interpretations issued by the IFRS Interpretations Committee, previously named International Financial Reporting Interpretations Committee (IFRIC) and initially Standing Interpretations Committee (SIC).

(2)
According to the requirements of the Conceptual Framework for IFRS, "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".

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Subsidiaries are consolidated from the date on which control is obtained until the date that such control ceases. 100% of assets, liabilities, income and expenses of consolidated subsidiaries are combined with those of the parent in the Consolidated Financial Statements; the net book value of these subsidiaries is eliminated against the corresponding portion of the shareholders' equity. Equity and net profit attributable to non-controlling interests are included in specific line items of equity and profit and loss account.

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 the Group 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/loss calculated as the difference between the consideration received and the corresponding transferred portion of equity; (ii) any gain or loss recognized as a result of the re-measurement of any investment retained in the former subsidiary to its fair value; and (iii) any amount related to the former subsidiary previously recognized in other comprehensive income which can be reclassified subsequently to the profit and loss account[3]. Any investment retained in the former subsidiary is recognized 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

A joint arrangement is an arrangement of which two or more parties have joint control. 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. Judgment is required in assessing whether a joint arrangement creates enforceable rights and obligations; this assessment is made considering the design and purpose of the joint arrangement, the terms of the contractual arrangements, as well as any other facts and circumstances that are relevant for this assessment. In the Consolidated Financial Statements the Eni's share of the assets/liabilities and revenues/ expenses of joint operations is recognized upon rights and obligations to the arrangements.

After the initial recognition, the assets/liabilities and revenues/expenses of the joint operations are measured in accordance with the measurement criteria applicable to each case. Immaterial 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.

Interests 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".

Consolidated companies' financial statements are audited by external auditors who audit also the information required for the preparation of the Consolidated Financial Statements.

(3)
Conversely, any amount related to the former subsidiary previously recognized in other comprehensive income, which cannot be reclassified subsequently to the profit and loss account, are reclassified within retained earnings.

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The equity method of accounting

Investments in immaterial subsidiaries, joint ventures and associates are accounted for using the equity method[4]. Under the equity method, investments are initially recognized 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 recognized 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. Changes in the net assets of an equity-accounted investee, not arising from the investee's profit or loss or other comprehensive income, are recognized in the investor's profit and loss account, as they basically represent a gain or loss from a disposal of an interest in the investee's equity. 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 (see also the accounting policy for "Current financial assets"), 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". Immaterial subsidiaries, joint ventures and associates are accounted for at cost, net of any impairment losses, if this does not result in a misrepresentation of the Group financial position and performance. When an impairment loss no longer exists or has decreased, a reversal of the impairment loss is recognized in the profit and loss account within "Other gain (loss) from investments". The reversal cannot exceed the previously recognized impairment losses.

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/loss calculated as the difference between the consideration received and the corresponding transferred share; (ii) any gain or loss recognized as a result of the re-measurement of any investment retained in the former joint venture/associate to its fair value[5]; and (iii) any amount related to the former joint venture/associate previously recognized in other comprehensive income which can be reclassified subsequently to profit and loss account[6]. Any investment retained in the former joint venture/associate is recognized 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 equity-accounted investee, that exceeds the carrying amount of the investment, is recognized in a specific provision only to the extent the investor is required to fulfill legal or constructive obligations of the investee or to fund its losses.

Business combinations

Business combinations are recognized by applying the acquisition method. The consideration transferred in a business combination is measured at the acquisition date and is the sum of the acquisition-date fair values of the assets transferred, the liabilities incurred, as well as any equity instruments issued by the acquirer. Acquisition-related costs are accounted for as expenses when they are incurred.

At the acquisition date, the acquirer shall measure the identifiable assets acquired and liabilities assumed at their acquisition-date fair values[7], 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 recognized as goodwill; a gain from a bargain purchase is recognized in the profit and loss account.

(4)
In the case of step acquisition of significant influence (or joint control), the investment is recognized, 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.

(5)
If the retained investment continues to be accounted for using the equity method, no remeasurement to fair value is recognized in the profit and loss account.

(6)
Conversely, any amount related to the former joint venture/associate previously recognized in other comprehensive income, which cannot be reclassified subsequently to the profit and loss account, are reclassified in another item of equity.

(7)
Fair value measurement principles are described below in the accounting policy for “Fair value measurements”.

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Any non-controlling interest is measured as the proportionate share in the recognized amounts of the acquiree's identifiable net assets at the acquisition date (partial goodwill method); as an alternative, it is allowed the recognition of the entire amount of goodwill deriving from the acquisition, including also the goodwill attributable to non-controlling interests (full goodwill method). In the last case, non-controlling interests are measured at their fair value, which therefore includes the goodwill attributable to them8. The choice of measurement basis of 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 fair value of previously held equity interests in the acquiree and the consideration transferred for the acquisition of control; the previously held equity interests are re-measured at their acquisition-date fair value and the resulting gain or loss, if any, is recognized in the profit and loss account. Furthermore, on obtaining control, any amount of the acquiree previously recognized in other comprehensive income is charged to the profit and loss account, or in another item of equity when the amount cannot be reclassified to the profit and loss account. If control is obtained over a business formerly classified as joint operation, the previously held interest in its assets and liabilities is not re-measured to its fair value.

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 recognized 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 in which the activity constitutes a business is recognized applying the relevant principles for business combinations.

Intragroup transactions

All balances and transactions between consolidated companies, including unrealized profits arising from such transactions, have been eliminated.

Unrealized 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, unrealized losses are not eliminated when they provide 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: WMR/IPSE).

The cumulative amount of the resulting translation differences is presented in the separate component of the Group shareholders' equity "Cumulative currency translation differences"9. Cumulative exchange differences are reclassified to the profit and loss account when the entity disposes the entire interest in a foreign operation or when the partial disposal involves the loss of control, joint control or significant influence of a 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.

(8)
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.

(9)
When the foreign subsidiary is partially owned, the cumulative exchange differences, that are attributable to the non-controlling interests, are allocated to and recognized as part of "Non-controlling interest".

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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 2014	Exchange rate at December 31, 2014	Annual average exchange rate 2015	Exchange rate at December 31, 2015	Annual average exchange rate 2016	Exchange rate at December 31, 2016
U.S. Dollar	1.33	1.21	1.11	1.09	1.11	1.05
Pound Sterling	0.81	0.78	0.73	0.73	0.82	0.86
Norwegian Krone	8.35	9.04	8.95	9.60	9.29	9.09
Australian Dollar	1.47	1.48	1.48	1.49	1.49	1.46

3 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 capitalized 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 amortized, 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 recognized in the profit and loss account as write-off. Lower value exploration rights are pooled and amortized 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". When the reclassification is recognized, 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 amortized according to the unit of production method (the so-called UOP method, described in the accounting policy for "UOP depreciation, depletion and amortization").

Acquisition of mineral interests

Costs incurred for the acquisition of mineral interests are capitalized 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 under the criteria indicated in the accounting policy for "Acquisition of exploration rights". Costs associated with proved reserves are amortized on a UOP basis (see the accounting policy for "UOP depreciation, depletion and amortization"). Expenditure associated with possible and probable reserves (unproved mineral interests) is not amortized 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 recognized as an expense as incurred.

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Costs directly associated with an exploration well are initially recognized 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 capitalized 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 capitalized 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 capitalized costs are recognized 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 recognized as unproved is reclassified to proved exploration and appraisal costs, within tangible assets in progress. When the reclassification is recognized, 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 amortization").

Development expenditure

Development expenditure, including the costs related to unsuccessful and damaged development wells, are capitalized as "Tangible asset in progress — proved". Development expenditures are costs incurred to obtain access to proved reserves and provide facilities to extract, gather and store the oil&gas. They are amortized, from the commencement of production, generally on a UOP basis (see the accounting policy for "UOP depreciation, depletion and amortization"). 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 amortization

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 amortized 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 recognized 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 production entitlements 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 representing the Profit Oil 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 recognize at the same time an increase in the taxable profit, through the increase of the revenues, 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 capitalized, consistently with the accounting policy described under "Property, plant and equipment", and then depreciated on a UOP basis.

Property, plant and equipment

Property, plant and equipment, including investment properties, are recognized using the cost model and stated at their purchase 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. When a substantial period of time is required to make the asset ready for use, the purchase price or construction cost includes the borrowing costs incurred that could have otherwise 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 recognized as part of a specific provision). Changes in provisions due to the passage of time and changes in discount rates are recognized as described in the accounting policy for "Provisions, contingent assets and liabilities"10.

Property, plant and equipment are not revalued for financial reporting purposes.

Assets 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 of ownership of the leased asset, are recognized, at the commencement of the lease term, at 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 financial debt to the lessor is recognized. These assets are depreciated as described below. If there is no reasonable certainty that the lessee will obtain ownership by the end of the lease term, the assets are depreciated over the shorter of the lease term and the useful life of the asset.

Expenditures on upgrading, revamping and reconversion are recognized 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 to obtain future economic benefits from other assets.

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 purchased with a building. Tangible assets held for sale are not depreciated (see the accounting policy for "Assets held for sale and discontinued operations" below). A change in the depreciation method, deriving from 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, shall be recognized prospectively.

Assets that can be used free of charge by third parties are depreciated over the shorter term of the duration of the concession or the asset's useful life.

Replacement costs of identifiable parts in complex assets are capitalized 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 recognized as an expense as incurred.

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

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These liabilities relate essentially to assets in the Exploration & Production segment. Decommissioning and restoration liabilities associated with tangible assets of Refining & Marketing, Chemical and Gas & Power segments/businesses are recognized when 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, Chemical and Gas & Power segments/ businesses for any changes in facts and circumstances that might require recognition of a decommissioning and restoration liability.

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 long-term planning assumptions and, if there is a sufficient liquidity and reliability level, on the forward prices prevailing in the marketplace. When commodity prices fluctuate quite considerably, management considers the most updated variables available.

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, 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 recognized in the profit and loss account. The reversal shall not exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

The carrying amount of property, plant and equipment is derecognized on disposal or when no future economic benefits are expected from its use or disposal; the arising gain or loss is recognized 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 acquired in business combinations. 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 recognized 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 amortized on a systematic basis over their useful life estimated as the period over which the assets will be available for use by the Company; the amount to be amortized 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 amortized. 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

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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[11], the excess is recognized 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 recognized for goodwill is not reversed in a subsequent period[12].

Directly attributable customer acquisition costs are capitalized when the following conditions are met: (i) the capitalized 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 revenues from the sales, or, where the customer withdraws from the contract in advance, through the collection of a penalty.

Costs of technological development activities are capitalized 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 derecognized on disposal or when no future economic benefits are expected from its use or disposal; any arising gain or loss is recognized in the profit and loss account.

Grants related to assets

Government grants related to assets are recognized 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 realizable value. Net realizable value is the net amount expected to be realized from the sale of inventories in the ordinary course of business, or, with reference to inventories of crude oil and petroleum products already included in binding sale contracts, the contractual sale 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 recognized 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 realizable value, determined adopting the same criteria described for inventories.

(11)
For the definition of recoverable amount see the accounting policy for "Property, plant and equipment".

(12)
Impairment losses recognized in an interim period are not reversed also when, considering conditions existing in a subsequent interim period, they would have been recognized in a smaller amount or would not have been recognized.

Financial instruments

Current financial assets

Cash and cash equivalents include cash on hand, demand deposits, as well as financial assets originally due within 90 days, readily convertible to known amount of cash and subject to an insignificant risk of changes in value.

Available-for-sale financial assets include financial assets other than derivative financial instruments, loans and receivables, held for trading financial assets and held-to-maturity financial assets.

Held-for-trading financial assets and available-for-sale financial assets are measured at fair value with gains or losses recognized in the line item of the profit and loss account "Finance income (expense)" and in the equity reserve[13] related to other comprehensive income, respectively. Changes in fair value of available-for-sale financial assets recognized in equity are charged to the profit and loss account when the assets are derecognized or impaired. The objective evidence that an impairment loss has occurred is verified considering, inter alia, significant breaches of contracts, serious financial difficulties or the risk of bankruptcy and other financial reorganization of the counterparty; impairment losses of available-for-sale financial assets are included in the carrying amount.

Interests and dividends on financial assets measured at fair value are accounted for on an accrual basis in "Finance income (expense)"[14] and "Other gain (loss) from investments", respectively. 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.

Receivables are measured at amortized cost (see below the accounting policy for "Non-current financial assets").

Non-current financial assets

Investments

Investments in equity instruments[15] are measured at fair value, with gains or losses recognized in the equity reserve related to other comprehensive income; the amounts recognized in equity are reclassified to the profit and loss account when the investment is impaired or derecognized.

When investments do not have a quoted price in an active market and their fair value cannot be reliably measured, they are measured at cost, net of any impairment losses; impairment losses shall not be reversed[16].

Receivables and held-to-maturity financial assets

Receivables and held-to-maturity financial assets are accounted for at cost, that is the fair value of the initial consideration plus transaction costs (e.g. fees, transaction costs, etc.). The initial carrying amount is then adjusted to take into account principal repayments, plus or minus the cumulative amortization of any difference between the initial amount and the maturity amount and minus any reductions for impairment or uncollectibility. Amortization is carried out on the basis of the effective interest rate represented by the rate that equalizes, at the moment of the initial recognition, the present value of expected cash flows to the initial carrying amount (so-called "amortized cost method").

Receivables for finance leases are recognized at an amount equal to the present value of the lease payments and the purchase option price or any residual value; the amount is discounted at the interest rate implicit in the lease.

(13)
Changes in the carrying amount of available-for-sale financial assets relating to changes in foreign exchange rates are recognized in the profit and loss account.

(14)
Interests accrued on held for trading financial assets impact the total fair value measurement of the instrument and are recognized, within the line item "Finance income (expense)", in the sub-item "Net finance income on financial assets held for trading". Conversely, interests accrued on financial assets available-for-sale are recognized, within the line item "Finance income (expense)", in the sub-item "Finance income".

(15)
For investments in joint ventures and associates, see "The equity method of accounting".

(16)

Impairment losses recognized in an interim period are not reversed also when, considering conditions existing in a subsequent interim period, they would have been recognized in a smaller amount or would not have been recognized.

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If there is objective evidence that an impairment loss has been incurred (see also the accounting policy for "Current financial assets"), the impairment loss is measured as the difference between the carrying amount and the present value of the expected cash flows discounted at the effective interest rate computed at initial recognition, or at the moment of its updating to reflect re-pricings contractually established. Receivables and held-to-maturity financial assets are presented net of the allowance for impairment losses; when the impairment loss is definite, the allowance for impairment losses is reversed for charges, otherwise for excess. Changes to the carrying amount of receivables or financial assets in accordance with the amortized cost method are recognized as "Finance income (expense)".

Financial liabilities

Financial liabilities, other than derivative financial instruments, are measured at amortized cost (see above the accounting policy for "Non-current financial assets").

Derivative financial instruments

Derivative financial instruments, including embedded derivatives (see below) that are separated from the host contract, are assets and liabilities measured at their fair value.

Derivatives are designated as hedging instruments when the relationship between the derivative and the hedged item is formally documented and the hedge is regarded as highly effective and reviewed on an ongoing basis. When derivatives hedge the risk of changes in the fair value of the hedged item (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 item (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 changes in the fair value of the derivatives, that are designated as effective hedging instruments, are initially recognized 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.

The changes in the fair value of derivatives, that are not designated as effective hedging instruments, are recognized 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 recognized 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 recognized in the profit and loss account line item "Other operating (expense) income".

Embedded derivatives in hybrid instruments are separated from the host contract and accounted for as a derivative if the hybrid instruments are not measured at fair value with changes in fair value recognized in the profit and loss account and if the economic characteristics and risks of the embedded derivatives are not closely related to those of the host contracts. 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 recognized 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 realize the asset and settle the liability simultaneously).

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Derecognition of financial assets and liabilities

Transferred financial assets are derecognized when the contractual rights to receive the cash flows from the financial assets are realized, expired or transferred. Financial liabilities are derecognized when they are extinguished, or when the obligation specified in the contract is discharged, cancelled or expired.

Provisions, contingent assets and liabilities

A provision is a liability of uncertain timing or amount at the balance sheet date. Provisions are recognized 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 recognized 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 recognized 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 recognized 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 recognized 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 recognized 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 recognized 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 recognized with a corresponding entry to the assets to which they refer, to the extent of the assets’ carrying amounts; any excess amount is recognized in the profit and loss account.

Contingent liabilities are disclosed as follows: (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 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 recognized unless the realization 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 recognized in the financial statements of the period in which the change occurs.

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.

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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 recognized 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 recognized 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 recognized within the statement of comprehensive income.

Re-measurements of the net defined benefit liability, recognized in the equity reserve related to other comprehensive income, are not reclassified to the profit and loss account in a subsequent period.

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.

Treasury shares

Treasury shares are recognized as deductions from equity at cost. Any gain or loss resulting from subsequent sales is recognized in equity.

Revenues and costs

Revenues from the sale of products and the rendering of services are recognized when the significant risks and rewards of ownership have been transferred to the customer or when the transaction can be considered settled and the associated revenue can be reliably measured. In particular, revenues are recognized for the sale of:

- crude oil, generally upon shipment;
- natural gas and electricity, upon delivery to the customer;
- petroleum products sold to retail distribution networks, generally upon delivery to the service stations, whereas all other sales of petroleum products are generally recognized upon shipment; and
- chemical products and other products, generally upon shipment.

Revenues are recognized upon shipment when, at that date, significant risks are transferred to the buyer.

Revenues from crude oil and natural gas production from properties in which Eni has an interest together with other producers are recognized on the basis of Eni's net working interest in those properties (entitlement method). Higher/lower production volume withdrawn as compared to Eni's net working interest volume is recognized at current prices at the balance sheet date.

Revenues arising from rendering of services are recognized by reference to the stage of completion at the end of the reporting period, provided that: (i) the amount of revenues can be measured reliably; (ii) it is probable that the economic benefits associated with the transaction will flow to the entity; (iii) the stage of completion of the transaction at the end of the reporting period can be measured reliably; and (iv) the related costs can be measured reliably. When the outcome of the transaction involving the rendering of services cannot be estimated reliably, revenue is recognized only to the extent of the expenses recognized that are recoverable.

Revenues are measured at the fair value of the consideration received or receivable net of returns, discounts, rebates, bonuses and related taxes. Amounts collected or to be collected on behalf of third parties are not revenues.

Award credits, related to customer loyalty programs, are recognized as a separately identifiable component of the sales transaction in which they are granted. Therefore, the consideration allocated to the award credits, measured by reference to their fair value, represents deferred revenues and it is recognized in

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the line item “Other liabilities”. The deferred revenues are reversed in the profit and loss account at the redemption or forfeiture of the award credits by customers. When goods or services are exchanged for goods or services that are of a similar nature and value, the exchange is not regarded as a transaction which generates a revenue.

Costs are recognized 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 recognized in relation to the amount of the carbon dioxide emissions that exceed free allowances. Costs related to the purchase of the emission rights are recognized as intangible assets net of any imbalance between the amount of actual emissions and the free allowances. Revenues related to emission quotas are recognized 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 recognized as a contra to the line item “Other income and revenues”.

Operating lease payments are recognized 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 capitalized (see above the accounting policy for “Intangible assets”), are included in the profit and loss account when they are incurred.

Grants not related to assets are recognized in the profit and loss account on an accrual basis matching the related costs when 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. 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 realizable value are retranslated using the exchange rate at the date when the value is determined.

Dividends

Dividends are recognized 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 income. The estimated liability is included in “Income taxes payable”. 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 recognized 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 have been enacted or substantively enacted for future years. Deferred tax assets are recognized when their recoverability is considered probable; in particular, deferred tax assets are recoverable 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 recognized to the extent that their recoverability is probable. Income tax assets that are uncertain in the amount to be recovered are recognized in accordance to 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 recognized 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

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included in 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 recognized in the line item “Deferred tax assets”; if negative, in the line item “Deferred tax liabilities”. When the results of transactions are recognized 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 amount will be recovered principally through a sale transaction rather than through their continuing use. For this to be the case, the sale must be highly probable and the asset or the disposal group must be 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. The classification of non-current assets (or disposal groups) as held for sale requires the management to perform subjective judgments based on assumptions deemed reasonable in consideration of the information available at the time.

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 recognized in the balance sheet separately from other assets and liabilities.

Immediately before the initial classification of a disposal group as held for sale, the assets and liabilities of the disposal group are measured in accordance with applicable IFRSs. Subsequently, non-current assets held for sale are not depreciated and they are measured at the lower of the fair value less costs to sell and their carrying amount. After the classification as held for sale of an equity-accounted investment, the investment, or the portion of the investment, that meets the criteria to be classified as held for sale, is no longer accounted for using the equity method; therefore, in this case, the carrying amount of the investment in accordance with the equity method represents the carrying amount for the measurement as non-current asset held for sale. 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 investment is measured in accordance with the measurement criteria indicated in the accounting policy for “Non-current financial assets — Investments”, 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 recognized up to the cumulative impairment losses, including those recognized prior to qualification of the asset as held for sale. Non-current assets and current and non-current assets included within disposal groups, classified as held for sale, 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 recognized 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 recognized 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.

If a discontinued operation is reclassified as held for use, its results previously presented in the separate line item of the profit and loss account are reclassified and included in income from continuing operations for all periods presented.

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

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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 maximize the value of the asset.

The fair value of a liability, both financial and non-financial, or of a 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 entity'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, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

4 Financial statements[17]

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[18]. Assets and liabilities are classified as current when: (i) they are expected to be realized/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 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 realized/ settled within twelve months after the balance sheet date; on the contrary they are classified as non-current.

The statement of comprehensive income shows net profit integrated with income and expenses that are recognized directly in equity according to IFRS.

The statement of changes in shareholders' equity includes the total comprehensive income 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 is adjusted for the effects of non-cash transactions.

5 Changes in accounting policies

In accordance with IAS 8 “Accounting Policies, Changes in Accounting Estimates and Errors”, the adoption of SEM represents a voluntary change in accounting policies, in order to increase the

(17)
The financial statements are the same presented in the last Annual Report on Form 20-F, with the exception of: (i) the profit and loss account and the statement of cash flows that include the new line item “Write-off” which presents the loss from the derecognition of property, plant and equipment or intangible assets. The presentation of this new line item is regarded as relevant by management due to the adoption, on a voluntary basis, of the recognition and measurement criteria for the costs related to the oil and gas activities in accordance with the Successful Efforts Method (SEM), as described in note 5 “Changes in accounting policies”; (ii) the profit and loss account that include the new line item “Net impairment losses (reversals)”, which includes the net balance of impairment losses/reversals of tangible and intangible assets. The presentation of this new line item is regarded as relevant by management in order to avoid that the compensation between depreciations/amortizations and net impairment reversals would provide a

misleading representation to users of financial statements.

(18)
Further information on financial instruments as classified in accordance with IFRS is provided in note 38 - Guarantees, commitments and risks — Other information about financial instruments.

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comparability with the companies operating in the same industry and provide a reliable and more relevant financial information. SEM has been applied retrospectively; therefore, comparative amounts have been restated. Under the previous accounting policy: (i) the costs for the acquisition of exploration rights were amortized on a straight-line basis over the exploration period as contractually established; (ii) the costs associated with exploration activities were initially capitalized, in order to reflect their nature as capital expenditure, and fully amortized as incurred. Furthermore, because of the withdrawal of Versalis sale plan, the criteria for its classification as disposal group and discontinued operations are no longer met; therefore the 2014 and 2015 comparative figures have been amended as if Versalis had never been classified as held for sale. The financial statements line items affected by the above-mentioned changes are presented below.

(€ million)	January 1, 2014		
Selected line items only	As reported	Adoption of the SEM	As restated
Non-current assets	85,584	4,085	89,669
- of which property, plant and equipment	63,763	3,524	67,287
- of which intagible assets	3,876	860	4,736
Non-current liabilities	44,283	1,081	45,364
Total Shareholders' Equity	61,049	3,004	64,053

(€ million)	January 1, 2015		
Selected line items only	As reported	Adoption of the SEM	As restated
Non-current assets	91,344	4,159	95,503
- of which property, plant and equipment	71,962	4,029	75,991
- of which intagible assets	3,645	775	4,420
Non-current liabilities	46,659	727	47,386
Total Shareholders' Equity	62,209	3,432	65,641

(€ million)	December 31, 2015			
Selected line items only	As reported	Restatement of Versalis in continuing operations	Adoption of the SEM	As restated
Current assets	39,982	1,388		41,370
Non-current assets	77,294	889	3,915	82,098
- of which property, plant and equipment	63,795	323	3,887	68,005
- of which intagible assets	2,433	55	546	3,034
Discontinued operations and assets held for sale	17,516	(1,983)		15,533
Current liabilities	29,565	370		29,935
Non-current liabilities	44,488	215	469	45,172
Discontinued operations and liabilities directly associated with assets held for sale	7,070	(585)		6,485
Total Shareholders' Equity	53,669	294	3,446	57,409

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(€ million)	2014			
Selected line items only	As reported	Restatement of Versalis in continuing operations	Adoption of the SEM	As restated
Revenue	94,226	5,078	(7)	99,297
Operating expense	73,930	3,106	368	77,404
Depreciation, amortization	9,134	99	(1,557)	7,676
Net impairment (reversal)	1,013	96	161	1,270
Write-off of tangible and intangible assets	137	1	1,060	1,198
Operating profit (loss)	7,585	1,419	(39)	8,965
Finance income and expense	(1,181)		14	(1,167)
Income (expense) from investments	469	(3)	10	476
Income taxes	6,681	(191)	(24)	6,466
Net profit – continuing operations	192	1,607	9	1,808
Net profit – discontinued operations	658	(1,607)		(949)
Net profit	850		9	859
Net profit attributable to Eni	1,291		12	1,303
- attributable to Eni in continuing operations	101	1,607	12	1,720
- attributable to Eni in discontinued operations	1,190	(1,607)		(417)
Net cash provided by operating activities	15,110		(368)	14,742
Net cash used in investing activities	(8,943)		368	(8,575)
Net cash used in financing activities	(5,062)			(5,062)
Net cash flow for the period	1,183			1,183

(€ million)	2015			
Selected line items only	As reported	Restatement of Versalis in continuing operations	Adoption of the SEM	As restated
Revenue	68,945	4,603	(10)	73,538
Operating expense	53,958	2,636	254	56,848
Depreciation, amortization	9,654	108	(822)	8,940
Net impairment (reversal)	4,826	998	710	6,534
Write-off of tangible and intangible assets	25		663	688
Operating profit (loss)	(2,781)	520	(815)	(3,076)
Finance income and expense	(1,323)	3	14	(1,306)
Income (expense) from investments	124	(20)	1	105
Income taxes	3,147	486	(511)	3,122
Net profit - continuing operations	(7,127)	17	(289)	(7,399)
Net profit - discontinued operations	(2,251)	277		(1,974)

Net profit	(9,378)	294	(289)	(9,373)
Net profit attributable to Eni	(8,783)	294	(289)	(8,778)
- attributable to Eni in continuing operations	(7,680)	17	(289)	(7,952)
- attributable to Eni in discontinued operations	(1,103)	277		(826)
Net cash provided by operating activities	11,903		(254)	11,649
Net cash used in investing activities	(11,177)		254	(10,923)
Net cash used in financing activities	(1,351)			(1,351)
Net cash flow for the period	(1,414)	9		(1,405)

The amendments to IFRSs effective from January 1, 2016 did not have a significant impact on the financial statements.

6 Significant accounting estimates or judgements

The preparation of the Consolidated Financial Statements requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses recognized in the financial statements, as well as amounts included in the notes thereto, including disclosure of contingent assets and liabilities. Estimates made are based on complex or subjective judgments and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and

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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 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 judgments, 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.

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 categorized 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 judgment.

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 expenditure 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 on at least an annual basis to confirm the continued intent to develop, or otherwise to extract value from the discovery.

Field reserves will be categorized 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 and depletion charges and impairment charges. Depreciation and depletion rates of oil&gas assets using the UOP basis are determined from the ratio between the amount of hydrocarbons extracted in the quarter and proved developed reserves existing at the end of the quarter increased by the amounts extracted during the quarter. Assuming all other variables are held constant, an increase in estimated proved developed reserves for each field decreases depreciation and depletion charge. Conversely, a decrease in estimated proved developed reserves increases depreciation 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. The larger is the volume of estimated reserves, the lower is the likelihood of asset impairment.

Impairment of assets

Assets are impaired when there are events or changes in circumstances that indicate that carrying amounts of the assets are not recoverable. Such impairment indicators include changes in the Group’s

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business plans, changes in commodity prices leading to unprofitable performance, a reduced capacity utilization 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 recognized 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. The amount of an impairment loss is determined by comparing the carrying amount of an asset with its recoverable amount. Recoverable amount of an asset is the higher of an asset's fair value less costs of disposal and its value in use. The estimate of an asset's value in use is based on the present value of the future cash flows expected to be derived from continuing use of the asset and, if significant and reasonably determinable, the cash flows expected to be obtained from the disposal of the asset at the end of its useful life after deducting the costs of disposal. The expected future cash flows used for impairment analyses are based on judgmental 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 specialized analysts and on management's forecasts about the evolution of the supply and demand fundamentals. The discount rate reflects the current market valuation of the time value of money and of the specific risks of the asset not reflected in the estimate of the future cash flows.

Goodwill and intangible assets with indefinite useful lives are not subject to amortization. The Company tests for impairment such assets on an annual basis and whenever there is any indication that they may be impaired. In particular, goodwill impairment is based on the lowest level (cash-generating unit) to which goodwill can be allocated on a reasonable and consistent basis. A cash-generating unit is the smallest aggregate on which the Company, directly or indirectly, evaluates the return on the capital expenditure. If the recoverable amount of a cash-generating unit, to which goodwill has been allocated, is less than its carrying amount, goodwill allocated to that cash-generating unit is impaired up to that difference; if the carrying amount of goodwill is lower than the amount of the impairment loss, the other assets of the cash-generating unit are impaired pro-rata on the basis of their carrying amounts for the residual difference, up to the recoverable amount of assets with finite useful lives.

Decommissioning and restoration liabilities

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 judgments 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. The complexity of these estimates is also due to the accounting that requires the initial recognition of the present value of the decommissioning and restoration liabilities as a part of the cost of property, plant and equipment. Then 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 and subjective managerial judgments.

Business combinations

Accounting for business combinations requires the allocation of the purchase price to the identifiable assets and liabilities of the acquired business generally at their fair values. Any positive residual difference is

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recognized as goodwill. Any negative residual difference is recognized in 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 recognized at the acquisition date are 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. Management uses all available information to make these fair value measurements and, for major business combinations, engages independent external advisors; the purchase price allocation, that requires, also in consideration of the available information, management to make complex judgments, is also relevant for the application of the equity method.

Environmental liabilities

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 recognized when it becomes probable that a liability will be incurred and the liability 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.

Employee benefits

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 reflect the rates at which benefits could be effectively settled, taking into account the duration of the obligation. Indicators used in selecting the discount rate include 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). The inflation rates reflect market conditions observed in the reference currency area; (ii) the future salary levels of the individual employees are determined including an estimate of future changes attributed 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 utilization 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. Re-measurements are recognized within statement of comprehensive income for defined benefit plans and within the profit and loss account for long-term plans.

Other provisions

In addition to liabilities related to environmental decommissioning and restoration liabilities and employee benefits, Eni recognizes provisions primarily related to legal and tax proceedings. These provisions are estimated on the basis of managerial judgments related to the amounts to recognize and the timing of future cash outflows. After the initial recognition, provisions are periodically reviewed and adjusted to reflect the current best estimate.

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Revenues and receivables

Revenues from the sale of electricity and gas to retail customers include amount accrued for electricity and gas supplied between the date of the last meter reading 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 management, which can impact on them. Therefore accrued revenues derive from complex estimates based on distributed and allocated volumes, communicated by third parties; these revenues may be adjusted, according to the applicable regulations, within the fifth year subsequent the one in which they were accrued.

Complex and/or subjective judgements are required in assessing the recoverability of overdue receivables and determining whether an allowance against those receivables is required. Factors considered include, among others, the credit rating of the counterparty (if available), the amount and timing of anticipated future payments, any collateral held as a security and other credit enhancements, as well as any possible actions that can be taken to mitigate the risk of non-payment.

7 IFRSs not yet adopted

On May 28, 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” (hereinafter IFRS 15), which sets out the requirements for recognizing and measuring revenues arising from contracts with customers, including construction contracts. In particular, IFRS 15 requires that, to recognize revenue, a company shall apply the following five steps: (i) identify the contract with the customer; (ii) identify the performance obligations (that are promises in a contract to transfer to a customer goods and/or services); (iii) determine the transaction price; (iv) allocate the transaction price to each performance obligation on the basis of the relative standalone selling prices of each good or service promised in the contract; and (v) recognize revenue when a performance obligation is satisfied. Moreover, IFRS 15 includes more disclosure requirements about the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied for annual periods beginning on or after January 1, 2018; IFRS 15 shall be applied retrospectively, by providing for the possibility of recognizing the cumulative effect of initially applying IFRS 15 as an adjustment to the opening balance of equity as January 1, 2018, having regard only to the contracts that are not completed at the date of initial application. Furthermore, on April 12, 2016, the IASB issued the document “Clarifications to IFRS 15 Revenue from Contracts with Customers” (hereinafter clarifications to IFRS 15), which provides clarifications to support implementation of the new standard. The clarifications to IFRS 15 shall be applied for annual periods beginning on or after January 1, 2018.

In 2016, the Group started analytical activities aimed to identify potentially critical issues for each operating segment, to assess the potential effects on the financial statements and verify the need to adjust internal control system over financial reporting. At the current stage of the analysis, the following areas may be affected by the new provisions of the standard: (i) accounting for certain types of agreements with partners within oil&gas projects, considering their different nature from customers; (ii) representation on a gross or net basis of certain types of costs closely related to supplying of goods or services; (iii) multiple-element arrangements; (iv) capitalization of the customer acquisition costs principally in the Gas & Power segment; (v) contracts with options to acquire additional goods/services that provide a material right that customers would not receive without entering into the contracts; (vi) contracts with variable consideration; (vii) licenses of intellectual property principally in the Refining & Marketing and Chemical segment.

On July 24, 2014, the IASB completed its project to replace IAS 39 by issuing the final version of IFRS 9 “Financial Instruments” (hereinafter IFRS 9). In particular, IFRS 9: (i) changes the classification and measurement approach for financial assets, basing it on the characteristics of the financial instrument and on the business model adopted by the entity for managing it; (ii) introduces a new impairment model for financial assets, which considers the expected credit losses; and (iii) includes an improved hedge accounting model. IFRS 9 shall be applied for annual periods beginning on or after January 1, 2018.

In 2016, the Group started analytical activities with reference to the three main updated areas above-mentioned. In particular, the Group is assessing if the new classification requirements of IFRS 9 will impact the current way of classification of financial instruments; at the current stage of the analysis, the Group has not identified relevant impacts. An in-depth analysis on the fair value measurements of minority

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investments in equity instruments that, under current provisions, are measured at cost when their fair value cannot be reliably measured, is being carried out.

With reference to the application of the expected credit loss model, the ongoing activities essentially concern: (i) for counterparties with an identifiable credit risk factor (e.g. the credit rating), the adoption of the expected loss model, defined having regard also to the current credit enhancements held (e.g. collaterals, guarantees, insurance contracts, etc.); (ii) for retail customers, the implementation of provision matrix to represent adequately the credit standing of the counterparty; and (iii) the revision and optimization of the operating processes to ensure the availability of information for implementing the evaluation models and drawing up the financial reporting.

In relation to hedge accounting, analyses on the applicability of the new qualifying criteria provided by IFRS 9 and on the implementation of rebalancing mechanism to maintain a hedge ratio that complies with the hedge effectiveness requirements, is being carried out.

At the current stage of the analyses, the likely impacts deriving from the application of the new IFRS 15 and IFRS 9 are not yet reasonably estimable.

On September 11, 2014, the IASB issued the amendments to IFRS 10 and IAS 28 “Sale or Contribution of Assets between an Investor and its Associate or Joint Venture” (hereinafter the amendments to IFRS 10 and IAS 28), which define the recognition criteria of the economic effects mainly related to the loss of control of an investment as a consequence of its transfer to an associate or a joint venture. On December 17, 2015, the IASB issued an amendment that postpones the application of the amendments to IFRS 10 and IAS 28 indefinitely.

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; for all leases with a term of more than 12 months, the lessee shall recognize an asset, as the right-of-use, and a liability, as the present value of the lease payments. Conversely, a lessor continues to classify its leases as operating leases or finance leases. IFRS 16 enhances disclosures both for lessees and for lessors. IFRS 16 shall be applied for annual periods beginning on or after January 1, 2019.

On January 19, 2016, the IASB issued the amendments to IAS 12 “Recognition of Deferred Tax Assets for Unrealized Losses”, which provide clarifications about the recognition and measurement of deferred tax assets. The amendments to IAS 12 shall be applied for annual periods beginning on or after January 1, 2017.

On January 29, 2016, the IASB issued the amendments to IAS 7 “Disclosure Initiative”, which enhance disclosures required in case of changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. The amendments to IAS 7 shall be applied for annual periods beginning on or after January 1, 2017.

On December 8, 2016, the IASB issued the IFRIC Interpretation 22 “Foreign Currency Transactions and Advance Consideration” (hereinafter IFRIC 22), which sets out that the exchange rate to use on initial recognition of an asset, expense or income related to an advance consideration, previously paid or received in a foreign currency, is the rate used at the date of initial recognition of the non-monetary asset or non-monetary liability arising from the payment or receipt of that advance consideration. The IFRIC 22 shall be applied for annual periods beginning on or after January 1, 2018.

On December 8, 2016, the IASB issued the document “Annual Improvements to IFRS Standards 2014-2016 Cycle”, which include, basically, technical and editorial changes to existing standards. The amendments to the standards shall be applied for annual periods beginning on or after January 1, 201819.

Eni is currently reviewing these new IFRSs to determine the likely impact on the Group’s results.

(19)
The clarification of the scope of the IFRS 12 “Disclosure of Interests in Other Entities” shall be applied for annual periods beginning on or after January 1, 2017.

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Current assets

8 Cash and cash equivalents

Cash and cash equivalents of €5,674 million (€5,209 million at December 31, 2015) included financial assets with maturity of three months or less at the date of inception amounting to €4,379 million (€3,289 million at December 31, 2015) and mainly included short-term deposits having notice of more than 48 hours.

The average maturity of financial assets due within 90 days was 7 days and the average interest rate was negative and amounted to 0.01% (positive 0.25% at December 31, 2015).

9 Financial assets held for trading

(€ million)	December 31, 2015	December 31, 2016
Quoted bonds issued by sovereign states	925	996
Other	4,103	5,170
	5,028	6,166

Financial assets held for trading of €6,166 million (€5,028 million at December 31, 2015) related to Eni SpA for €6,062 million (€5,028 million at December 31, 2015) and to Eni Insurance DAC per €104 million.

Financial assets held for trading of Eni SpA include securities subject to lending agreements of €665 million. The Company has established a liquidity reserve as part of its internal targets and financial strategy. The management of this liquidity reserve is performed through trading activities in view of the financial optimization of returns, within a predefined level of risk tolerance, targeting the preservation of the invested capital and the ability to promptly convert it into cash.

The breakdown by currency is provided below:

(€ million)	December 31, 2015	December 31, 2016
Euro	3,906	4,319
U.S. dollar	272	699
British pound	271	632
Swiss franc	524	413
Canadian dollar	36	52
Australian dollar	19	51
	5,028	6,166

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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	539	548	Baa2	BBB-
Spain	158	166	Baa2	BBB+
Poland	62	64	A2	BBB+
Slovenia	33	36	Baa3	A
Germany	23	24	Aaa	AAA
Ireland	10	11	A3	A+
Chile	8	8	Aa3	AA-
Slovakia	5	5	A2	A+
Sweden	5	5	Aaa	AAA
	843	867		
Floating rate bonds				
Italy	100	100	Baa2	BBB-
Spain	30	29	Baa2	BBB+
	130	129		
Total quoted bonds issued by sovereign states	973	996		
Other Bonds				
Fixed rate bonds				
Quoted bonds issued by industrial companies	2,264	2,344	from Aaa to Baa3	from AAA to BBB-
Quoted bonds issued by financial and insurance companies	1,981	2,031	from Aaa to Baa3	from AAA to BBB-
European Investment Bank	8	8	Aaa	AAA
	4,253	4,383		
Floating rate bonds				
Quoted bonds issued by financial and insurance companies	553	556	from Aaa to Baa3	from AAA to BBB-
Quoted bonds issued by industrial companies	231	231	from Aaa to Baa3	from AAA to BBB-
	784	787		
Total other bonds	5,037	5,170		
Total other financial assets held for trading	6,010	6,166		

The fair value was determined based on market quotations. The fair value hierarchy is level 1.

10 Financial assets available for sale

(€ million)	December 31, 2015	December 31, 2016

Securities held for operating purposes		
Quoted bonds issued by sovereign states	243	
Quoted securities issued by financial institutions	39	
	282	
Securities held for non-operating purposes		
Quoted bonds issued by sovereign states		210
Quoted securities issued by financial institutions		28
		238
Total	282	238

The breakdown by currency is provided below:

(€ million)	December 31, 2015	December 31, 2016
Euro	241	199
U.S. Dollar	41	39
	282	238

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At December 31, 2016, bonds issued by sovereign states amounted to €210 million (€243 million at December 31, 2015). The breakdown is presented below:

	Nominal value (€ million)	Fair Value (€ million)	Nominal rate of return (%)	Maturity date	Rating – Moody's	Rating – S&P
Fixed rate bonds						
Belgium	27	32	from 3.75 to 4.25	from 2019 to 2021	Aa3	AA
Spain	25	28	from 1.40 to 5.50	from 2018 to 2021	Baa2	BBB+
Italy	22	22	from 0.00 to 3.50	from 2017 to 2020	Baa2	BBB-
France	17	19	from 1.00 to 3.25	from 2018 to 2023	Aa2	AA
Poland	16	19	from 4.50 to 6.38	from 2019 to 2022	A2	BBB+
Ireland	16	18	from 0.80 to 4.40	from 2019 to 2022	A3	A+
Iceland	15	16	from 2.50 to 5.88	from 2020 to 2022	A3	BBB+
Slovakia	10	10	from 1.50 to 4.20	from 2017 to 2018	A2	A+
Finland	9	9	from 1.13 to 1.75	from 2017 to 2019	Aa1	AA+
Portugal	7	8	4.75	2019	Ba1	BB+
Czech Republic	7	8	3.63	2021	A1	AA-
Slovenia	7	8	2.25	2022	Baa3	A
United States of America	7	7	from 1.25 to 3.13	from 2019 to 2020	Aaa	AA+
Canada	5	5	1.63	2019	Aaa	AAA
Netherlands	1	1	4.00	2018	Aaa	AAA
Total	191	210				

Quoted securities amounting to €28 million (€39 million at December 31, 2015) were issued by financial institutions with a rating from Aaa to Aa1 (Moody's) and from AAA to AA (S&P).

Securities held for non-operating purposes of €238 million related to the Group's insurance company Eni Insurance DAC.

From January 1, 2016, insurance companies are required to meet certain capital and solvency ratios as minimum requirements to continue performing the insurance activity based on the provisions of EU Solvency II Directive (the so-called Minimum Capital Requirement — MCR — and Solvency Capital Requirement — SCR). Therefore, while it is advisable to maintain a sound investment policy of the proceeds associated with the business, insurance companies have been waived from committing financial assets to funding the loss provisions. Accordingly, available-for-sale securities held by Eni's subsidiary Eni Insurance DAC at the opening balance for €282 million have been reclassified as held for non-operating purposes. The same reclassification has been applied to financial receivables held by Eni Insurance DAC (see note 11 — Trade and other receivables).

The effects of fair value measurement of securities are set out below:

(€ million)	Carrying amount at December 31, 2015	Changes recognized in equity	Reversal of the year	Carrying amount at December 31, 2016
Fair value	9	(3)	(1)	5
Deferred tax liabilities	(1)			(1)
Other reserves of shareholders' equity	8	(3)	(1)	4

The fair value was determined based on market quotations. The fair value hierarchy is level 1.

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11 Trade and other receivables

(€ million)	December 31, 2015	December 31, 2016
Trade receivables	12,616	11,186
Financing receivables		
- for operating purposes – short-term	375	86
- for operating purposes – current portion of long-term receivables	1,247	72
- for non-operating purposes	685	385
	2,307	543
Other receivables		
- from disposals	33	171
- other	6,684	5,693
	6,717	5,864
	21,640	17,593

Trade receivables decreased by €1,430 million, of which €1,298 million in the Gas & Power segment because an increased volume of receivables were sold to financial institutions as a result of factoring transactions.
Receivables are stated net of the valuation allowance for doubtful accounts of €2,371 million (€2,083 million at December 31, 2015):

(€ million)	Carrying amount at December 31, 2015	Additions	Deductions	Other changes	Carrying amount at December 31, 2016
Trade receivables	1,915	503	(607)	6	1,817
Financing receivables	66			2	68
Other receivables	102	367	(4)	21	486
	2,083	870	(611)	29	2,371

Additions to allowance for doubtful accounts amounted to €503 million (€588 million in 2015) and related mainly to the Gas & Power segment for €399 million. This is reflective of the continuing difficulties in the collection of overdue receivables in the retail customers segment. The mitigation measures regarding the counterparty risk executed by Eni through specific actions of recovery and through specialized external services have led to a reduction of overdue receivables during the year 2016.
Utilizations amounting to €607 million (€249 million in 2015) related to the Gas & Power segment for €559 million and related to the recognition of losses on doubtful accounts in the retail business.
At December 31, 2016, Eni sold without recourse trade receivables due in 2017 for €1,769 million to financial institutions (€750 million at December 31, 2015 due in 2016). Derecognized receivables related to the Gas & Power segment (€1,434 million) and to the Refining & Marketing and Chemical segment (€335 million).
Trade receivables outstanding at December 31, 2016 comprised receivables of €1,764 million for hydrocarbons supplies made by the Exploration & Production segment to national oil companies. That amount includes overdue receivables related to: (i) State-owned oil companies in Egypt, which overdue amount was €420 million. This was significantly lower than the overdue amount of €771 million outstanding at December 31, 2015 and was driven by the implementation of a plan intended to trim the overdue amounts, which comprised the settlement of certain commercial and industrial agreements with the counterparties. The residual amount outstanding at the reporting date has been further reduced by a payment dated January 2017 amounting to $240 million (€228 million); (ii) State-owned

companies in Iran as part of a settlement agreement signed in 2015 regarding the recovery of past costs associated to certain petroleum projects already completed for €264 million. This amount was curtailed compared to December 31, 2015 (€312 million). The State counterparties expressed their willingness to negotiate a repayment plan of overdue receivables based on arrangements relating the sale of volumes of the Iranian counterpart equity crude and the attribution to Eni of a percentage of the sale proceeds. This agreement

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has been firstly enacted in the last months of 2016 with a reimbursement to Eni of $44 million (€42 million). Negotiations are underway to identify additional crude volumes to be marketed, some of which have already been awarded to Eni in early 2017, with the aim of fully recovering the overdue amounts.

The ageing of trade and other receivables is presented below:

(€ million)	December 31, 2015 Trade receivables	December 31, 2015 Other receivables	December 31, 2016 Trade receivables	December 31, 2016 Other receivables
Neither impaired nor past due	9,814	5,371	9,243	4,869
Impaired (net of the valuation for doubtful accounts)	1,085	93	759	432
Not impaired and past due in the following periods:				
- within 90 days	1,080	92	744	58
- 3 to 6 months	110	502	49	81
- 6 to 12 months	226	485	69	249
- over 12 months	301	174	322	175
	1,717	1,253	1,184	563
	12,616	6,717	11,186	5,864

The Group has not booked any counterparty loss on certain trade and other receivables which were overdue at the balance sheet date, because they pertained to highly-rated Italian and foreign public administrations, to other highly-reliable counterparties for supplies of oil, natural gas, refined and chemical products and to retail customers of the Gas & Power segment overdue by less than 90 days.

Trade receivables in currencies other than euro amounted to €3,629 million (€3,995 million at December 31, 2015).

Financing receivables associated with operating purposes of €158 million (€1,622 million at December 31, 2015) included loans granted to joint ventures and associates to fund the execution of Eni's capital projects for €28 million (€1,135 million at December 31, 2015). The decrease for €1,464 million comprised the reclassification for €1,054 million to other non-current financial assets of the financing loan granted to the equity-accounted investee CARDÓN IV SA (Eni's share being 50%) (€1,112 million at December 31, 2015).

Financing receivables for operating purposes outstanding at December 31, 2015, of €287 million relating to Eni Insurance DAC were reclassified as financing receivables not associated with operating activities following the adoption of the provisions of EU Solvency II Directive on capital requirements to be met for operating in the insurance activity. More information is reported in note 10 — Financial assets available for sale.

Financing receivables not associated with operating activities amounted to €385 million (€685 million at December 31, 2015) and related to: (i) restricted deposits in escrow for €137 million of Eni Trading & Shipping SpA (€209 million at December 31, 2015) of which €113 million with BNP Paribas and €24 million with Citibank relating to derivatives; (ii) deposits of Eni Insurance DAC for €225 million.

Financing receivables in currencies other than euro amounted to €121 million (€1,329 million as of December 31, 2015).

Receivables from divestments amounted to €171 million (€33 million at December 31, 2015), of which €166 million related to the current portion of the receivable arising from the divestment finalized in 2008 of a 1.71% interest in the Kashagan project to the local partner KazMunayGas for a total amount of €463 million. The reimbursement of the receivable is scheduled in three annual instalments commencing from the date when the agreed production target is achieved. The receivable accrues interest income at market rates. Due to the restart of the project, the production milestone was reached in the fourth quarter 2016 and, consequently, the first installment of the sale price including interests has been repaid (€152 million). The description of the transaction is provided in note 23 — Other non-current assets.

Other receivables of €5,693 million (€6,684 million at December 31, 2015) included €4,111 million of receivables owed by Eni's partners in unincorporated joint ventures that are currently executing exploration

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and production projects. The largest outstanding amount as of December 31, 2016 related to partners in Nigeria (€1,775 million) and among these the Nigerian national oil company NNPC in respect of: (i) receivables of €382 million (€773 million at December 31, 2015) related to the contractual recovery of costs incurred for two oil projects (one of which is operated) under arbitration procedures. After the issuance of favorable arbitration rulings, the Company is negotiating a settlement agreement with the aim of being reimbursed of a part of the amount awarded by the arbitration procedures. The amount being negotiated will be reimbursed through the assignment to Eni of crude oil quantities owned by the state company over a period of three years. The impairment loss related to the receivables resulting from the agreement under negotiation amounted to €332 million plus the discount effect of the expected future cash flows, which reflected the mineral risk (€42 million); (ii) receivables of €716 million were overdue at the balance sheet date in relation to the cash calls owed by NNPC at certain projects operated by Eni. At the opening balance, part of these receivables was denominated in local currency and consequently their carrying amounts were negatively affected by the currency devaluation occurred in 2016. Eni and NNPC agreed on a repayment plan providing for a reimbursement in U.S. dollars and the attribution to Eni of a portion of the proceeds from the sale of the hydrocarbon productions which will be obtained from development activities with a low risk profile (rigless) in order to fully repay the overdue amounts within a period of five years. The expenses through profit included foreign exchange losses for $80 million (€72 million) and the discounting effect for $96 million (€87 million), which was determined taking into account the mineral risk.

Other receivables were as follows:

(€ million)	December 31, 2015	December 31, 2016
Receivables originated from divestments	33	171
Accounts receivable from		
- joint venture partners in exploration and production	4,656	4,111
- prepayments for services	540	372
- insurance companies	113	147
- non-financial government entities	104	49
- factoring arrangements	90	81
- non-Italian oil entities for oil tax refunds	27	40
- other receivables	1,154	893
	6,684	5,693
	6,717	5,864

Receivables from joint venture partners in exploration and production activities of €60 million (€281 million at December 31, 2015) included the liability for benefit plans (see note 31 — Provisions for employee benefits).

Receivables from factoring arrangements of €81 million (€90 million at December 31, 2015) related to Serfactoring SpA and consisted of advances for factoring arrangements with recourse and receivables for factoring arrangements without recourse.

Other receivables in currencies other than euro amounted to €5,253 million (€5,913 million at December 31, 2015).

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 described in note 47 — Transactions with related parties.

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12 Inventories

(€ million)	December 31, 2015 Crude oil, gas and petroleum products	Chemical products	Other	Total	December 31, 2016 Crude oil, gas and petroleum products	Chemical products	Other	Total
Raw and auxiliary materials and consumables	222	142	1,933	2,297	550	135	1,903	2,588
Products being processed and semi-finished products	97	9	1	107	99	9	1	109
Work in progress			7	7			2	2
Finished products and goods	1,573	448	72	2,093	1,394	389	86	1,869
Certificates and emission rights			75	75			69	69
	1,892	599	2,088	4,579	2,043	533	2,061	4,637

Other inventories of raw and auxiliary materials and consumables of €1,903 million (€1,933 million at December 31, 2015) related to the Exploration & Production segment for €1,699 million (€1,732 million at December 31, 2015) and primarily comprised materials relating to perforation activities and the maintenance of infrastructures and facilities.
Certificates and emission rights of €69 million (€75 million at December 31, 2015) are measured at the fair value determined based on market quotations. The fair value hierarchy is level 1.
Inventories of €82 million (€87 million at December 31, 2015) were pledged to guarantee the potential balancing with respect to Snam Rete Gas SpA.
Changes in inventories and in the loss provision were as follows:

(€ million)	Carrying amount at the beginning of the year	Changes	New or increased provisions	Deductions	Currency translation differences	Other changes	Carrying amount at the end of the year
2015							
Gross carrying amount	8,027	(1,082)			249	(2,307)	4,887
Loss provision	(472)		(93)	212	(10)	55	(308)
Net carrying amount	7,555	(1,082)	(93)	212	239	(2,252)	4,579
2016							
Gross carrying amount	4,887	(29)			61	(27)	4,892
Loss provision	(308)		(125)	163	(5)	20	(255)
Net carrying amount	4,579	(29)	(125)	163	56	(7)	4,637

Negative changes of the period amounting to €29 million related to the Chemical business line for €96 million partially offset by the increase in the Refining & Marketing segment for €75 million. The increase in loss provision of €125 million related to the Exploration & Production segment for €72 million. Deductions of €163 million for loss provision primarily related to the Refining & Marketing business line (€122 million).
Other changes of €2,252 million as of December 31, 2015, included the reclassification of €2,183 million as discontinued operations.

13 Current tax assets

(€ million)	December 31, 2015	December 31, 2016
Italian subsidiaries	182	134
Subsidiaries outside Italy	178	249
	360	383

Income taxes are described in note 43 — Income tax expense.

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14 Other current tax assets

(€ million)	December 31, 2015	December 31, 2016
VAT	386	447
Excise and customs duties	121	161
Other taxes and duties	123	81
	630	689

15 Other current assets

(€ million)	December 31, 2015	December 31, 2016
Fair value of derivative financial instruments	3,220	2,248
Other current assets	422	343
	3,642	2,591

The fair value related to derivative financial instruments is disclosed in note 34 — Derivative financial instruments.
Other assets amounting to €343 million (€422 million at December 31, 2015) included gas volumes prepayments that were made in previous reporting period due to the take-or-pay obligations in the Company's long-term supply contracts, as the Company is forecasting to make-up the underlying gas volumes in the next 12 months. The residual amount as of December 31, 2016 for €90 million reflected the off-taken of underlying volumes achieved during the period that reduced the amount outstanding at the end of 2015 by €108 million. In 2016, the carrying amount of the prepayment, assimilated to a receivable in kind, was written down by €24 million to align it to the current prices of gas.
Transactions with related parties are described in note 47 — Transactions with related parties.

Non-current assets

16 Property, plant and equipment

(€ million)	Net book amount at the beginning of the year	Additions	Depreciation	Net Impairments/reversal	Write-off	Currency translation differences	Reclassification to discontinued operations and assets held for sale	Other changes	Net book amount at the end of the year
2015									
Land	615	1				(13)	(98)	5	510
Buildings	1,633	32	(70)	(47)		16	(602)	(144)	818
Plant and machinery	47,506	369	(8,403)	(3,624)		3,276	(6,264)	7,807	40,667
Industrial and commercial equipment	590	49	(85)	(1)	(2)	14	(197)	(42)	326
Other assets	458	57	(88)	(6)		17	(37)	2	403
Tangible assets in	25,189	10,669		(2,312)	(676)	2,009	(311)	(9,287)	25,281

progress and advances									
	75,991	11,177	(8,646)	(5,990)	(678)	5,319	(7,509)	(1,659)	68,005
2016									
Land	510	1		(64)		1	(8)	8	448
Buildings	818	22	(66)	(3)		1	(2)	40	810
Plant and machinery	40,667	204	(7,087)	345	(198)	1,329	(1)	15,011	50,270
Industrial and commercial equipment	326	32	(66)	(1)	(2)			11	300
Other assets	403	42	(89)	(17)		4		(34)	309
Tangible assets in progress and advances	25,281	8,766		(174)	(89)	551		(15,679)	18,656
	68,005	9,067	(7,308)	86	(289)	1,886	(11)	(643)	70,793

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A breakdown by segment of capital expenditures made in 2016 is provided below:

(€ million)	2015	2016
Capital expenditure		
Exploration & Production	9,943	8,217
Gas & Power	109	66
Refining & Marketing and Chemical	614	655
Engineering & Construction	550	
Corporate and other activities	46	42
Elimination of intragroup profits	(85)	87
	11,177	9,067

Capital expenditures included capitalized finance expenses of €105 million (€165 million in 2015) and related to the Exploration & Production segment (€90 million). The interest rates used for capitalizing finance expense ranged from 2.7% to 5.3% (2.4% and 5.3% at December 31, 2015).

The main depreciation rates used were substantially unchanged from the previous year and ranged as follows:

(%)			
Buildings	2	-	10
Plant and machinery	2	-	15
Industrial and commercial equipment	4	-	33
Other assets	6	-	33

The criteria adopted by Eni for determining net impairments/reversals is reported in note 19 — Impairment/reversal of tangible and intangible assets.

Write-off of €289 million (€678 million in 2015) related for €193 million to the EST conversion plant units at the Sannazzaro refinery, damaged in an accident occurred in December 2016. The Exploration & Production booked €93 million of asset write-offs (€676 million in 2015), of which €88 million mainly relating exploration wells capitalized in previous reporting periods. Wells write-offs comprised suspended exploration wells that did not encountered enough quantities of commercial hydrocarbons to justify their completion as productive wells in Libya, Angola, Congo and Indonesia.

Foreign currency translation differences of €1,886 million primarily related to translations of entities accounts denominated in U.S. dollar (€1,761 million), Norwegian krone (€318 million) and, as decrease, in in British pound (€215 million).

Other changes of €643 million related to the initial recognition and change in estimates of decommissioning costs and site restoration in the Exploration & Production segment amounting to €665 million (€817 million at December 31, 2015) mainly due to a steeper discount rate curve, especially for the U.S. dollar and to the revision of cost estimates. These effects were partially offset by the recognition of new obligations incurred during the year. Other changes in tangible assets in progress and advances of €15,679 million included the reclassification from plant and machinery of the carrying amount of the idle units of the EST plant of the Sannazzaro refinery for €485 million until the re-entry into operations of the damaged section.

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Tangible assets in progress and advances include costs related to exploration activities and appraisal and tangible assets in progress and advances of the Exploration & Production segment:

(€ million)	Book amount at the beginning of the year	Additions	Net impairments/ reversals	Write-off	Reclassifications	Other changes and currency translation differences	Book amount at the end of the year
2015							
Exploration activity and appraisal							
Exploratory wells in progress	196	558		(106)	(572)	17	93
Exploratory wells completed and being evaluated	1,568			(501)	520	150	1,737
Exploratory successful wells in progress	813		(91)		5	80	807
	2,577	558	(91)	(607)	(47)	247	2,637
Other tangible assets in progress							
Unproved mineral interest	3,092		(998)		(203)	321	2,212
Wells and plants in progress	17,958	9,346	(866)	(69)	(8,107)	1,196	19,458
	21,050	9,346	(1,864)	(69)	(8,310)	1,517	21,670
	23,627	9,904	(1,955)	(676)	(8,357)	1,764	24,307
2016							
Exploration activity and appraisal							
Exploratory wells in progress	93	402			(282)	8	221
Exploratory wells completed and being evaluated	1,737			(109)	6	50	1,684
Exploratory successful wells in progress	807		(5)		78	33	913
	2,637	402	(5)	(109)	(198)	91	2,818
Other tangible assets in progress							
Unproved mineral interest	2,212	2	190		(35)	81	2,450
	19,458	7,777	(210)	(6)	(15,699)	370	11,690

Wells and plants in progress							
Abandonment cost				27		55	82
	21,670	7,779	(20)	21	(15,734)	506	14,222
	24,307	8,181	(25)	(88)	(15,932)	597	17,040

Reclassifications of €15,932 million mainly related to wells and production plants started to production in the year for €15,699 million, particularly due to the start-up of major oil&gas projects such as the Kashagan project in Kazakhstan, the Goliat project in Norway and the 'Mpungi field in the West Hub project, Block 15/06 in Angola.
The following information relates to the stratification of the suspended wells pending final determination of proved reserves (aging) and the projects to which they relate:

(€ million)	2014	2015	2016
Costs for exploratory wells suspended at the beginning of the period	1,618	1,568	1,737
Additions pending the determination of proved reserves	373	550	282
Amounts charged to expense	(267)	(501)	(109)
Reclassification to productive wells on determination of proved reserves	(314)	(30)	(276)
Sales		(4)	
Exchange differences	158	154	50
Costs for exploratory wells suspended at the end of the period	1,568	1,737	1,684

	2014		2015		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	392	7.85	368	5.32	16	1.05
- between 1 and 3 years	756	15.07	634	11.14	609	10.25
- beyond 3 years	420	12.87	735	18.97	1,059	21.55
	1,568	35.79				