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

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

Title of each class	Name of each exchange on which registered

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

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None
Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
Ordinary 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 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;

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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;

- 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

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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 (CO_2) 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 CO_2 regulated future. These processes can lead to projects being stopped, designs being changed, and potential GHG mitigation investments being identified, in preparation for when 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 CO_2 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 CO_2 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 CO_2 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 CO_2 costs of $133/tonne (in nominal terms) in 2030, our portfolio sensitivity to oil and gas prices exceeds our sensitivity to CO_2 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 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.

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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.

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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 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

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							