ENI SPA
Form 20-F
April 12, 2016

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, 2015

OR

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

OR

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

Commission file number: 1-14090

Eni SpA

(Exact name of Registrant as specified in its charter)

Republic of Italy

(Jurisdiction of incorporation or organization)

1, piazzale Enrico Mattei - 00144 Roma - Italy

(Address of principal executive offices)

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

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

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

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None

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

Ordinary shares of euro 1.00 each

3,634,185,330

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

Yes No

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

Yes No

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

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

Yes No

Indicate by check mark whether the registrant (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 have 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 if 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 similar expressions are intended to identify such forward-looking statements. These forward-looking statements are only predictions and are subject to risks, uncertainties, and assumptions that are difficult to predict because they relate to events and depend on circumstances that will occur in the future. Therefore, Eni s actual results may differ materially and adversely from those expressed or implied in any forward-looking statements. Factors that might cause or contribute to such differences include, but are not limited to, those discussed in this Annual Report on Form 20-F under the section entitled "Risk factors" and elsewhere. Any forward-looking statements made by or on behalf of Eni speak only as of the date they are made. Eni does not undertake to update forward-looking statements to reflect any changes in Eni s expectations with regard thereto or any changes in events, conditions or circumstances on which any such statement is based. The reader should, however, consult any further disclosures Eni may make in documents it files with the SEC.

CERTAIN DEFINED TERMS

In this Form 20-F, the terms "Eni", the "Group", or the "Company" refer to the parent company Eni SpA and its consolidated subsidiaries and, unless the context otherwise requires, their respective predecessor companies.
All references to "Italy" or the "State" are references to the Republic of Italy, all references to the "Government" are references to the government of the Republic of Italy. For definitions of certain oil&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 IFRS 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", " " and "EUR" 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 Eni s business activities: Exploration & Production, Gas & Power, Refining & Marketing, Engineering & Construction, Chemical and 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&gas terms is available on Eni s web page at the address eni.com. Below is a selection of the most frequently used terms.

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 which in the case of the Company refers to IFRS, 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 which in the case of the Company refers to IFRS, see "Item 5 Financial condition".
TSR (Total Shareholder Return)	Management uses this measure to asses the total return of the Eni share. It is calculated on a yearly basis, keeping account of changes in prices (beginning and 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 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 National Commission for listed companies and the Stock Exchange of Italy.
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.

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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&gas.
Enhanced recovery	Techniques used to increase or stretch over time the production of wells.
EPC	Engineering, Procurement and Construction.
EPCI	Engineering, Procurement, Construction and Installation.
Exploration	Oil and natural gas exploration that includes land surveys, geological and geophysical studies, seismic data gathering and analysis and well drilling.
FPSO	Floating Production Storage and Offloading System.
FSO	Floating Storage and Offloading System.
Infilling wells	Infilling wells are wells drilled in a producing area in order to improve the recovery of hydrocarbons from the field and to maintain and/or increase production levels.
LNG	Liquefied Natural Gas obtained through the cooling of natural gas to minus 160 °C at normal pressure. The gas is liquefied to allow transportation from the place of extraction to the sites at which it is transformed back into its natural gaseous state and consumed. One tonne of LNG corresponds to 1,400 cubic meters of gas.
LPG	Liquefied Petroleum Gas, a mix of light petroleum fractions, gaseous at normal pressure and easily liquefied at room temperature through limited compression.
Margin	The difference between the average selling price and direct acquisition cost of a finished product or raw material excluding other production costs (e.g. refining margin, margin on distribution of natural gas and petroleum products or margin of petrochemical products). Margin trends reflect the trading environment and are, to a certain extent, a gauge of industry profitability.
Mineral Potential	(Potentially recoverable hydrocarbon volumes) Estimated recoverable volumes which cannot be defined as reserves due to a number of reasons, such as the temporary lack of viable markets, a possible commercial recovery dependent on the development of new technologies, or for their location in accumulations yet to be developed or where evaluation of known accumulations is still at an early stage.
Mineral Storage	According to Legislative Decree No. 164/2000, these are volumes required for allowing optimal operation of natural gas fields in Italy for technical and economic reasons. The purpose is to ensure production flexibility as required by long-term purchase contracts as well as to cover technical risks associated with production.

Modulation Storage	According to Legislative Decree No. 164/2000, these are volumes required for meeting hourly, daily and seasonal swings in demand.
Natural gas liquids (NGL)	Liquid or liquefied hydrocarbons recovered from natural gas through separation equipment or natural gas treatment plants. Propane, normal-butane and isobutane, isopentane and pentane plus, that were previously defined as natural gasoline, are natural gas liquids.
Network Code	A code containing norms and regulations for access to, management and operation of natural gas pipelines.
Over/Under lifting	Agreements stipulated between partners which regulate the right of each to its share in the production for a set period of time. Amounts lifted by a partner different from the agreed amounts determine temporary Over/Under lifting situations.
Possible reserves	Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
Probable reserves	Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
Primary balanced refining capacity	Maximum amount of feedstock that can be processed in a refinery to obtain finished products measured in BBL/d.
Production Sharing Agreement (PSA)	Contract 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&gas reserves are those quantities of oil&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&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&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&gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
Reserve life index	Ratio between the amount of proved reserves at the end of the year and total production for the year.
Reserve replacement ratio	Measure of the reserves produced replaced by proved reserves. Indicates the company s ability to add new reserves through exploration and purchase of property. A rate higher than 100% indicates that more reserves were added than produced in

	the period. The ratio should be averaged on a three-year period in order to reduce the distortion deriving from the purchase of proved property, the revision of previous estimates, enhanced recovery, improvement in recovery rates and changes in the amount of reserves in PSAs due to changes in international oil prices.
Ship-or-pay	Clause included in natural gas transportation contracts according to which the customer is requested to pay for the transportation of gas whether or not the gas is actually transported.
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.
Upstream/Downstream	The term upstream refers to all hydrocarbon exploration and production activities. The term downstream includes all activities inherent to the oil&gas sector that are downstream of exploration and production activities.

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ABBREVIATIONS

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

CONVERSION TABLE

1 acre	= 0.405 hectares	
1 barrel	= 42 U.S. gallons	
1 BOE	= 1 barrel of crude oil	= 5,492 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 0.00643 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, 2011, 2012, 2013, 2014 and 2015.

Eni s results of operations and cash flow as at and for the twelve months ended December 31, 2015 have been prepared in addition to the consolidated basis, stating separately continuing operations from discontinued operations, the latter accounted for in accordance to IFRS 5. Discontinued operations comprise:

The Engineering & Construction operating segment which is managed by Eni s subsidiary Saipem SpA. On January 22, 2016, there was the closing of the preliminary agreements signed on October 27, 2015 with the Fondo Strategico Italiano (FSI). Those include the sale of a 12.503% stake of the share capital of Saipem to FSI and the concurrent enter into force of a shareholder agreement with Eni, which was intended to establish joint control over the former Eni subsidiary. Therefore effective for the full year, Saipem revenues and expenses and cash flow have been classified as discontinued operations and its assets and liabilities have been classified as held for sale. In addition as provided by IFRS 5, Eni s net assets in Saipem have been aligned to the lower of their carrying amount and fair value given by the share price at the reporting date.

The Chemical segment managed by Eni s wholly-owned subsidiary Versalis SpA. As of the reporting date, negotiations were underway to define an agreement with an industrial partner who, by acquiring a controlling stake of Versalis, would support Eni in implementing the industrial plan designed to upgrade this business. Therefore, effective for the full year, likewise Saipem, Versalis revenues and expenses and cash flow have been classified as discontinued operations and its assets and liabilities have been classified as held for sale. In addition, Eni s net assets in Versalis have been aligned to the lower of their carrying amount and their fair value based on the transaction that is underway.

Comparative results of operations and cash flow for the year 2014 and 2013 have been restated accordingly as dictated by IFRS 5.

Also the selected historical financial data for the years 2012 and 2011 have been restated accordingly.

All such data should be read in connection with the Consolidated Financial Statements and the related notes thereto included in Item 18.

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	Year ended December 31,				
	2011	2012	2013	2014	2015
	(euro million except data per share and per ADR)				
CONSOLIDATED PROFIT STATEMENT DATA					
Net sales from continuing operations	90,978	109,412	98,547	93,187	67,740
Operating profit (loss) by segment from continuing operations					
Exploration & Production	15,887	18,470	14,868	10,766	(144)
Gas & Power	(323)	(3,129)	(2,923)	64	(1,258)
Refining & Marketing	(276)	(1,260)	(1,534)	(2,107)	(552)
Corporate and Other activities	(746)	(641)	(736)	(518)	(497)
Impact of unrealized intragroup profit elimination and other consolidation adjustments (1)	(26)	(607)	(1,808)	(620)	(330)
Operating profit (loss) from continuing operations	14,516	12,833	7,867	7,585	(2,781)
Net profit (loss) attributable to Eni from continuing operations	4,675	2,097	3,472	101	(7,680)
Net profit (loss) attributable to Eni from discontinued operations	2,185	5,693	1,688	1,190	(1,103)
Net profit (loss) attributable to Eni	6,860	7,790	5,160	1,291	(8,783)
Data per ordinary share (euro) (2)					
Operating profit (loss):					
- basic	4.01	3.54	2.17	(0.17)	(0.77)
- diluted	4.01	3.54	2.17	(0.17)	(0.77)
Net profit (loss) attributable to Eni basic and diluted from continuing operations	1.29	0.58	0.96	0.03	(2.13)
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	0.60	1.57	0.46	0.33	(0.31)
Net profit (loss) attributable to Eni basic and diluted	1.89	2.15	1.42	0.36	(2.44)
Data per ADR ($) (2) (3)					
Operating profit (loss):					
- basic	11.16	9.10	5.77	(0.46)	(1.71)
- diluted	11.16	9.10	5.77	(0.46)	(1.71)
Net profit (loss) attributable to Eni basic and diluted from continuing operations	3.59	1.48	2.55	0.08	(4.73)
Net profit (loss) attributable to Eni basic and diluted from discontinued operations	1.68	4.04	1.22	0.88	(0.69)
Net profit (loss) attributable to Eni basic and diluted	5.26	5.53	3.77	0.96	(5.42)

(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 2015 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 12, 2016.

(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/USD 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 2011 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 2015 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 October 7, 2015, while the balance of euro 0.80 per ADR was translated at the Noon Buying Rate as recorded on December 31, 2015. The balance dividend for 2015 once the full-year dividend is approved by the Annual General Shareholders Meeting is payable on May 25, 2016 to holders of Eni shares, being the ex-dividend date May 23, 2016, while ADRs holders will be paid on June 7, 2016.

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	As of December 31,				
	2011	2012	2013	2014	2015
	(euro million except data per share and per ADR)				
CONSOLIDATED BALANCE SHEET DATA					
Total assets	142,945	140,192	138,341	146,207	134,792
Short-term and long-term debt	29,597	24,192	25,560	25,891	27,776
Capital stock issued	4,005	4,005	4,005	4,005	4,005
Minority interest	4,921	3,357	2,839	2,455	1,916
Shareholders equity - Eni share	55,472	59,060	58,210	59,754	51,753
Capital expenditures from continuing operations	11,909	12,805	11,584	11,264	10,775
Weighted average number of ordinary shares outstanding (fully diluted - shares million)	3,623	3,623	3,623	3,610	3,601
Dividend per share (euro) (1)	1.04	1.08	1.10	1.12	0.80
Dividend per ADR ($) (1) (2)	2.73	2.82	2.99	2.65	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 2015 is based on the proposal of Eni s management which is submitted to approval at the Annual General Shareholders Meeting scheduled on May 12, 2016.

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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, 2011, 2012, 2013, 2014 and 2015.

	Year ended December 31,				
	2011	**2012**	**2013**	**2014**	**2015**
Proved reserves of liquids of consolidated subsidiaries at period end (mmBBL)	3,134	3,084	3,079	3,077	3,372
of which developed	*1,850*	*1,762*	*1,831*	*1,847*	*2,100*
Proved reserves of liquids of equity-accounted entities at period end (mmBBL)	300	266	148	149	187
of which developed	*45*	*44*	*35*	*46*	*48*
Proved reserves of natural gas of consolidated subsidiaries at period end (BCF)	15,582	14,190	14,442	14,808	14,302
of which developed	*10,363*	*8,965*	*8,542*	*8,342*	*8,899*
Proved reserves of natural gas of equity-accounted entities at period end (BCF)	4,700	6,767	3,726	3,737	3,993
of which developed	*53*	*424*	*34*	*120*	*1,402*
Proved reserves of hydrocarbons of consolidated subsidiaries at period end (mmBOE)	5,940	5,667	5,708	5,772	5,975
of which developed	*3,716*	*3,394*	*3,387*	*3,366*	*3,720*
Proved reserves of hydrocarbons of equity-accounted entities at period end (mmBOE)	1,146	1,499	827	830	915
of which developed	*54*	*122*	*40*	*67*	*303*
Average daily production of liquids (KBBL/d) (1)	845	882	833	828	908
Average daily production of natural gas available for sale (mmCF/d) (2)	3,763	4,118	3,868	3,782	4,284
Average daily production of hydrocarbons available for sale (KBOE/d) (2)	1,523	1,631	1,537	1,517	1,688
Hydrocarbon production sold (mmBOE)	548.5	598.7	555.3	549.5	614.1
Oil and gas production costs per BOE (2)	10.86	10.82	12.19	12.00	9.18
Profit (loss) per barrel of oil equivalent (3)	16.98	15.95	15.46	9.90	(3.20)

(1) Referred to Eni s subsidiaries and its equity-accounted entities. Natural gas production volumes exclude gas consumed in operations (321, 383, 451, 442 and 397 mmCF/d in 2011, 2012, 2013, 2014 and 2015, 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&gas information in "Item 18 Notes on Consolidated Financial Statements".

(3) Expressed in U.S. dollars. Results of operations from oil&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&gas information in "Item 18 Notes on Consolidated Financial Statements" for a calculation of results of operations from oil and gas producing activities.

Selected Operating Information *continued*

	Year ended December 31,				
	2011	2012	2013	2014	2015
Sales of natural gas to third parties (1)	77.84	77.87	77.67	76.11	79.06
Natural gas consumed by Eni (1)	6.21	6.43	5.93	5.62	5.88
Sales of natural gas of affiliates (Eni s share) (1)	9.85	8.29	6.96	4.38	2.78
Total sales and own consumption of natural gas of the Gas & Power segment (1)	93.90	92.59	90.56	86.11	87.72
E&P natural gas sales in Europe and in the Gulf of Mexico (1)	2.86	2.73	2.61	3.06	3.16
Worldwide natural gas sales (1)	96.76	95.32	93.17	89.17	90.88
Electricity sold (2)	40.28	42.58	35.05	33.58	34.88
Refinery throughputs (3)	31.96	30.01	27.38	25.03	26.41
Balanced capacity of wholly-owned refineries (4)	574	574	574	404	388
Retail sales (in Italy and rest of Europe) (3)	11.37	10.87	9.69	9.21	8.89
Number of service stations at period end (in Italy and rest of Europe)	6,287	6,384	6,386	6,220	5,846
Average throughput per service station (in Italy and rest of Europe) (5)	2,206	2,064	1,828	1,725	1,754
Employees at period end (number) (6)	28,209	30,350	30,970	29,403	29,053

(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) Relating 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 euro)			
Year ended December 31,				
2011	1.49	1.29	1.39	1.29
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

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

	High	Low	At period end
	(U.S. dollars per euro)		
October 2015	1.14	1.10	1.10
November 2015	1.10	1.06	1.06

December 2015	1.10	1.06	1.09
January 2016	1.10	1.07	1.08
February 2016	1.14	1.09	1.09
March 2016	1.14	1.08	1.14

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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 31, 2015 was $1.14 per euro 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 and oil products

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&gas supply and demand. The price of crude oil has been on a downtrend since the second half of 2014 with oil prices falling from the level of approximately 110 $/BBL (where "BBL" means barrel) by mid-year, down to multi-year lows below the 30-dollar mark in January 2016. For the full year 2015, the benchmark Brent crude oil price averaged 53 $/BBL with a reduction of approximately 50% year-on-year. This decline was driven by structural imbalances in the global oil market on the back of continued oversupplies fuelled by production growth in both Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC countries, as well as uncertainties about the pace of macroeconomic growth. However, according to our records, demand for fuels held remarkably well in 2015, posting one of the best increase of the latest years, which was spurred by price elasticity and other factors. Looking forward, we believe that there are risks of further price erosion in 2016, as witnessed by trends in crude oil prices in the first months of the year, reflecting continued oversupplies, increased risks of a slowdown in global economic activity, a rise in global stockpiles of crude oil and the return of Iran s oil to the global market as sanctions are being lifted following its nuclear agreement with Western countries. Furthermore, uncertainties exist among market participants about the long-term prospects of the global energy demand also considering the growing political and institutional focus on energy conservation and reduction in Greenhouse Gas ("GHG") emissions;
- global political developments, including sanctions imposed on certain producing countries and conflict situations;
- global economic and financial market conditions;
- the influence of 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.

All these factors can affect the global balance between demand and supply for oil and prices of oil.

Management believes that a gradual absorption of the supply glut in the medium to long-term may occur, as a result of reduced investments by international oil companies, possible oil-producing countries agreements to curb output, a reduction in OPEC s spare capacity and the probable forcing of less efficient players, such as the operators in the U.S. tight oil production which we believe to have a cost structure no longer sustainable under the current scenario, out of the market. However, management has evaluated a number of risks and uncertainties inherent in such expectations, including structural changes that have been affecting oil industry e.g. the increase in oil supply following U.S. tight oil revolution 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 emissions. Based on this outlook, Eni s management has revised downwards its pricing assumptions of the Brent crude oil marker utilized in each of the periods of the Company s 2016-2019 strategic plan, in particular the long-term reference price has been reduced to 65 $/BBL, down from the 90-dollar scenario utilized in the previous planning assumptions and in evaluating recoverability of the carrying amounts of our oil&gas assets.

Price fluctuations have had in 2015 and may continue to have a material adverse effect on the Group s results of operations and cash flow. See "Item 5 Operating and Financial Review and Prospects". Lower oil prices from one year to another 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 euro 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 2016 at 40 $/BBL. Free cash flow is expected to reduce/increase by a corresponding amount.

In addition to the adverse effect on revenues, profitability and cash flow, lower oil&gas prices could result in the debooking of proved reserves, if they become economically unfavorable in this type of environment, and asset impairments. In 2015, we debooked 84 million BOE of proved reserves because decreases in commodity prices shortened the economic lives of certain producing properties and caused certain development projects to become economically unfavorable. In 2015, we recorded impairment losses at our oil&gas properties in the region of euro 5 billion (euro 3.5 billion post-tax) which were mainly driven by our revised outlook for commodity prices.

Depending on the significant 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&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 at development projects, either planned or implemented, forcing the Company to reschedule, postpone or cancel development projects. We are currently planning a capital budget of approximately euro 37 billion in the next four years excluding expenditures associated with our planned disposals, which is significantly lower than our previous financial projections, down by 21% on constant exchange rate basis, to take into account the expected lower cash flow from operations under our reduced price outlook in the years 2016-2019. We are forecasting crude oil prices in the range of 40 to 65 $/BBL in the next four years, which is significantly lower than our previous planning assumption of 55-90 $/BBL. Finally, lower oil prices over prolonged periods may trigger a review of the future recoverability of the Company s carrying amounts of oil&gas properties, resulting in the recognition of significant further impairment charges. In response to weakened oil&gas industry conditions and resulting revisions made to rating agency commodity price assumptions, lower commodity prices may also reduce our access to capital and lead to a downgrade or other negative rating action with respect to our 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 our cost of capital, increase our financial expenses, and may limit our ability to access capital markets and execute aspects of our business plans. See also "Item 18 note 28 Long-term debt and current portion of long-term debt of the Notes on Consolidated Financial Statements".

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 fall in crude oil prices. (See also the section on the specific risks of the Exploration & Production segment "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 our 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.

In gas markets, price volatility reflects the dynamics of demand and supply for natural gas. Over the latest 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 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 specific risk-factors section of 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. In case 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 affected by current downward trends in gas prices.

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

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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 license 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 an 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 industry-wide cost increases to a greater extent compared to its larger competitors given its potentially smaller market power with respect to suppliers. If, as a result 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. The use of gas in gas-fired power plants has registered a dramatic decline due to the replacement with coal reflecting 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 ended to supply the already saturated European sector. The continuing growth in the production of shale gas in the United States 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 main producing countries bordering Europe (namely Russia 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 meaningful improvement in the European gas sector for the foreseeable future. Gas demand will remain weak 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 to 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

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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 the industrial and in the commercial activities. Refining margins have been negatively impacted by declining demand due to growing energy efficiency and the economic downturn, as well as by growing competition from new large scale refineries in the Middle East, benefiting of low production costs. In 2015, refining margins rebounded as a consequence of falling oil price and a recovery in oil products demand. Looking forward, management believes that refining margins will remain under pressure. In 2016, Eni forecasts a lower refining margin than in 2015. In marketing Eni faces the challenges of a growing competition from no logo operators and large retailers, which leverage on the price awareness of the final consumers to increase their market share.

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. 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 from 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 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 the share price and the dividends.

Eni s activities in the Refining & Marketing segment entails 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 contaminations.

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, maritime, river-maritime, rail, road, 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. 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 s insurance subsidiary provides insurance coverage to Eni s entities, generally up to $1.1 billion in case of offshore incident and $1.5 billion in case of incident at onshore facilities (refineries). In addition, the Company also maintains worldwide third-party liability insurance coverage for all of its subsidiaries. Management believes that its insurance coverage is in line with industry practice and 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 BP Deepwater Horizon, 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 above mentioned could have a material adverse impact on the Group s business, competitive position, cash flow, results of operations, liquidity, future growth prospects, shareholders returns and damage 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&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 2015, approximately 52% of Eni s total oil&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&gas industry are inherently riskier than onshore activities. Offshore accidents and spills could have impacts also of catastrophic proportions on the ecosystem and health and security of people due to the 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, 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&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 as a result of a large variety of factors, including geological play 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, also 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

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and financial risks associated with these activities. The Company plans to conduct exploration projects offshore West Africa (Angola, Nigeria, Congo, and Gabon), East Africa (Mozambique and South Africa), South-East Asia (Indonesia, Vietnam, Myanmar and other locations), Australia, the Norwegian Barents Sea, the Mediterranean and offshore Gulf of Mexico. In 2015, the Company spent euro 0.8 billion to conduct exploration projects and plans to spend approximately euro 0.9 billion on average in the next four-year plan on exploration activities. 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 co-venturers, governments and State-owned companies, suppliers, customers or others, including, for example, Eni s ability to negotiate favorable long-term contracts to market gas reserves;
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons;
- timely issuance of permits and licenses by government agencies;
- the 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, for example by obtaining more favorable contractual terms by suppliers of equipment and services;
- the ability to carefully carry out front-end engineering design so as to prevent the occurrence of technical inconvenience during the execution phase;
- timely manufacturing and delivery of critical equipment by contractors, shortages in the availability of such equipment or lack of shipping yards where complex offshore units such as FPSO and platforms are built; these events may cause cost overruns and delays impacting the time-to-market of the reserves;
- risks associated with the use of new technologies and the inability to develop advanced technologies to maximize the recoverability rate of hydrocarbons or gain access to previously inaccessible reservoirs;
- 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. Due to the recent downtrend in crude oil prices, the Company is seeking to renegotiate construction contracts, daily rates for rigs and other field services and costs for materials and other productive factors to preserve margins at its development projects. In case it fail to obtaining the planned cost reductions, its profitability in the Exploration & Production segment could be adversely affected;

the actual performance of the reservoir and natural field decline; and

the ability and time necessary to build suitable transport infrastructures to export production to final markets.

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-lead-time projects are exposed to the volatility of oil&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 co-venturers 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 operation control of the joint ventures in which it participates and may have exposure to counterparty credit risk and disruption of operation and strategic objectives due to the nature of its relationships.

Finally, in case 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.

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For example, we have incurred cost overruns and continuing delays in the achievement of first oil at the Kashagan offshore field in the Kazakh section of the Caspian Sea. The latest issue related to a pipeline for the transport of acid gas where a spillage occurred, forcing the Consortium to shut down production. The damaged pipeline needs to be replaced and activities are underway. Management believes that production will resume as early as in late 2016. See "Item 4 Exploration & Production Kashagan".

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 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 expenditures. The opposite occurs in case of lower oil prices. Future oil&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 portion of oil&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.

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 production sharing agreements 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 preceding 12 months. For the 12-months ending December 31, 2015, average prices were based on 54 $/BBL for the Brent crude oil which compared to a price reference of 101 $/BBL in 2014. 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 84 mmBOE.

Commodity prices declined significantly in the fourth quarter of 2015 and in the first quarter of 2016 and if such prices do not increase significantly, our future calculations of estimated proved reserves will be based on lower commodity prices which could result in our having to remove non-economic reserves from our proved reserves in future periods. This effect will be counterbalanced in full or in part by increased reserves corresponding to the additional volume entitlements under Eni s PSAs relating to cost oil: i.e. because of lower oil and gas prices, the reimbursement of expenditures incurred by the Company requires additional volumes of reserves.

Many of these factors, assumptions and variables involved in estimating proved reserves are subject to change over time, therefore impact the estimates of oil and natural gas reserves. Accordingly, the estimated reserves reported as of the end of the period covered by this filing 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 our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Our proved undeveloped reserves may not be ultimately developed or produced

At December 31, 2015, approximately 42% of our 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. Our reserve estimates assume we can and will make these expenditures and conduct these operations successfully. These assumptions may not prove to be accurate. Our reserve report at December 31, 2015 includes estimates of total future development costs associated with our proved undeveloped reserves of approximately euro 38 billion (undiscounted). We 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 as estimated. In case of change in the Company s development plans to develop of those reserves, or if we are not otherwise able to successfully develop these reserves as a result of our inability to fund necessary capital expenditures or otherwise, we will be required to remove the associated volumes from our reported proved reserves.

Oil and gas activity are subject to high levels of income taxes

The oil&gas industry is subject to the payment of royalties and income taxes, which tend to be higher than those payable in many other commercial activities. In addition, in recent years, Eni has experienced adverse changes in the tax regimes applicable to oil&gas operations in a number of countries where the Company conducts its upstream operations. Because of these trends, management estimates that the tax rate applicable to the Company s oil&gas operations is materially higher than the Italian statutory tax rate for corporate profit, which currently stands at 27.5 per cent. See also "Item 18 note 42 Income taxes of the Notes on Consolidated Financial Statements".

The effective tax rate of the Company s Exploration & Production segment for the fiscal year 2015 was estimated at approximately 80 per cent driven by: (i) the recognition of a major part of positive pre-tax results in PSA contracts, which, although more resilient in a low-price environment, nonetheless bear higher-than-average rates of tax; and (ii) a higher incidence of certain non-deductible expenses on the pre-tax profit that has been lowered by the scenario. Also this outsized tax rate was due to the fact that in certain jurisdictions we were unable to match before-tax losses with the recognition of deferred tax assets due to lack of expected future taxable profit against which those asset can be utilized. Looking forward management believes that the tax rate in this segment will continue being negatively affected by those factors due to the persistence of weak commodity prices.

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

In the current uncertain financial and economic environment also due to falling oil prices, governments are facing greater pressure on public finances, which may increase their motivation to intervene in the fiscal framework for the oil&gas industry, including the risk of increased taxation, windfall taxes, nationalization and expropriations.

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

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

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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, 2015, the net present value of Eni s proved reserves totaled approximately euro 37.8 billion, calculated in accordance with the requirements of FASB Extractive Activities - Oil & Gas (Topic 932), significantly lower than in 2014 due to reduced commodity prices. The average price used to estimate Eni s proved reserves and the net present value at December 31, 2015, as calculated in accordance with U.S. SEC rules, was 54 $/BBL for the Brent crude oil that compares to 101 $/BBL in 2014. Future prices may materially differ from those used in our year-end estimates. Commodity prices have decreased significantly in recent months. Holding all other factors constant, if commodity prices used in Eni s year-end reserve estimates were in line with the pricing environment existing in the first quarter of 2016, Eni s PV-10 at December 31, 2016 could decrease significantly.

Political considerations

A substantial portion of Eni s oil&gas reserves and gas supplies are located in countries outside the EU and the 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, 2015, approximately 81% 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;
- unfavorable 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&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 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. As of the balance sheet date receivables for euro 773 million relating to cost recovery under certain petroleum contracts in a non-OECD country were the subject of an arbitration proceeding;

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 environment; and

complex process in granting authorizations or licenses affecting time-to-market of certain development projects.

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Areas where Eni operates, where the Company is particularly exposed to the political risk include, but are not limited to: Libya, Egypt, Algeria, Nigeria, Angola, Indonesia, 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 recent years, Eni s production levels in Libya were negatively impacted by an internal revolution and a change of regime in 2011, which led to a prolonged period of political and social instability characterized by acts of local conflict, social unrest, protests, strikes and other similar events. Those political development forced Eni to temporarily interrupt or reduce its producing activities, negatively affecting Eni s results of operations and cash flow until the situation began to stabilize. Although our production levels in Libya for the year 2015 returned to levels not seen from the outbreak of the civil war, the geopolitical situation remains unstable and unpredictable. In 2015, Libya accounted for approximately 20% of the Group total hydrocarbons production for the year and going forward its contribution albeit slowing down will remain significant. In case of major unfavorable geopolitical developments in Libya including but not limited to, a resurgence of civil war, renewed internal tensions, civil disorder or any other outbreak of violence, we could be forced to shut down our operations and interrupt production which could significantly and negatively affect our results of operations, cash flow, business prospects and shareholder value. Also 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. Looking forward, Eni expects that those risks will continue to affect Eni s operations in those countries. Particularly, the uncertain geopolitical outlook in Libya and unsafe operational conditions onshore Nigeria were factored up to a certain extent in the Company s projections of future production levels in these two countries. See "Item 5 Management s expectations of operations".

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 factors. State-owned petroleum companies of those countries are exposed to a liquidity risk too. Eni is partnering those national oil companies in executing certain oil&gas development projects. A possible sovereign default might jeopardize the financial feasibility of ongoing projects or increase the financial exposure of Eni, which is contractually obligated to finance the share of development expenditures of the first party in case of a financial shortfall of the latter. This risk is mitigated by the customary default clause, 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.

In Egypt, we have experienced continued difficulties in collecting overdue trading receivables for the supply of our share of oil&gas production to local oil&gas companies. As of December 31, 2015, Eni owned a significant amount of trade receivables due (euro 771 million) in respect of supplies of its oil&gas entitlements to local companies. Management is currently addressing the recoverability of the Company s trade receivables vs. Egyptian counterparties leveraging various initiatives and commercial agreements. Eni has not experienced any disruptions in its producing activities in the Country to date.

Eni closely monitors political, social and economic risks of approximately 60 countries in which 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, it is likely that the occurrence of any such events could adversely affect Eni s results from operations, cash flow and business prospects.

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

Eni is closely monitoring developments to the political situation in Russia, Ukraine and the Crimea Region and is adapting its business activities to the sanctions adopted by the relevant authorities in Europe and the U.S. targeting the financial sector and the energy sector in Russia in view of Russia s actions intended to destabilize the political framework in Ukraine. Eni will adapt to any further related regulations and/or economic sanctions that could be adopted by the Authorities. The EU enacted Regulation No. 833/2014, which is restricting, inter alia, the supply of certain oil&gas items to Russia and certain forms of financing related to the oil and gas sector in Russia.

Approximately 30% of Eni s natural gas is supplied by Russia and Eni is currently partnering the Russian company Rosneft in executing exploration activities in the Russian sections of the Barents Sea and the Black Sea. Contracts pertaining to the above mentioned exploration licenses were entered into before enactment of the restrictive measures and have been put on hold since then. Eni started the required authorization procedure before the relevant EU Member States Authorities who granted the Company certain authorizations that are valid throughout the whole European Union. However, given the uncertainty surrounding this matter, Eni cannot exclude major delays in certain ongoing or planned oil&gas projects in Russia.

It is possible that wider sanctions covering the Russian energy, banking and/or finance industries may be implemented, which may be targeted at specific individuals or companies or more generally. Further sanctions imposed on Russia, Russian individuals or Russian companies by the international community, such as sanctions enacting restrictions on purchases of Russian gas by European companies or restricting dealings with Russian counterparties could adversely impact Eni s business, results of operations and cash flow. In addition, an escalation of the crisis and of imposed sanctions could result in 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

We expect a weak trading environment in our Gas & Power segment, which will negatively affect the profitability outlook in this business

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 weak demand growth due to macroeconomic uncertainties, muted thermoelectric consumption, continuing oversupplies and strong competition. 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. Our financial outlook has factored in the rigidities of the Company s long-term supply contracts with take-or-pay clauses, where the Company is obligated to offtake a contractually set minimum volume of gas supplies or, in case of failure, to pay the contractual price (see below).

The main source of risk is concerning Eni s wholesale business which results are exposed to the volatility of the spreads between spot prices at European hubs and Italian spot prices because our supply costs are mainly indexed to spot prices at European hubs, whereas a large part of our 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 states the right of each counterparty to renegotiate the economic terms and other contractual conditions periodically, in relation to ongoing changes in the gas scenario. Management believes that the outcome of those renegotiations is uncertain in respect of both the amount of the economic benefits that will be ultimately achieved and the timing of recognition in profit. Furthermore, in case Eni and the gas suppliers fail to agree on revised contractual terms, the claiming party has faculty to open an arbitration procedure to obtain revised contractual conditions. This would add to the level of uncertainty surrounding the outcome and timing of those renegotiations. In 2015, the results of operations in the Gas & Power segment were negatively affected by a delay in the settlement of an arbitration procedure with a long-term supplier, which management had budgeted to recognize in that year, owing to the complexity of the matter. These considerations also apply to ongoing renegotiations with our long-term buyers. In 2015, the performance of our Gas & Power business was negatively affected by the unfavorable outcome of an arbitration procedure with one of our long-term buyer, where the amount of the discount on the price of gas awarded to the claimant was higher than our initial provision. Based on these risk factors, we believe that future results of the Gas Marketing activities are subject to increasing volatility and unpredictability.

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 of supplying the Italian gas market and anticipating certain trends in gas demand which actually failed to materialize, Eni has signed a number of long-term gas supply contracts with national operators of certain key producing countries, which include Russia, Algeria, Libya, Norway and the Netherlands, where most of European gas supplies are sourced from.

These contracts have a residual life of approximately 12 years. 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. The take-or-pay clause entitles the Company to off-take pre-paid volumes of gas in later years. Amounts of cash pre-payments and time schedules for off-taking pre-paid gas vary from contract to contract. Generally, cash pre-payments are calculated on the basis of the energy prices current in the year when the Company is scheduled to purchase the gas, with the balance due in the year when the gas is actually purchased.

The right to off-take pre-paid gas expires within a ten-year term in some contracts or remains in place until contract expiration in other arrangements. In addition, the right to off-take the pre-paid gas can be exercised in future years if the Company fulfills its minimum take obligation in a given year and within the limit of the maximum annual quantity. Similar considerations apply to ship-or-pay contractual obligations.

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Looking forward, management believes that the current market outlook which will be driven by a weak recovery in gas demand, continued oversupplies and strong competitive pressures as well as any possible change in sector-specific regulation represents a risk factor to the Company s ability to fulfill its minimum take obligations associated with its long-term supply contracts. Adding to this risk, the Company is currently forecasting sales volumes to remain flat or to decrease slightly in 2016 and in the subsequent years compared to 2015.

Furthermore, the above mentioned take-or-pay clause exposes the Company to a price risk because the cost of gas that the Company recognizes at the incurrence of the take-or-pay clause may be higher than the current cost of gas supplies in the year when the accrued gas is actually reversed through profit and loss. In 2015, the segment operating profit was hit by a euro 150 million charge in connection to this factor.

Risks associated with sector-specific regulations in Italy

Risks associated with the regulatory powers entrusted to the Italian Authority for Electricity and Gas in the matter of pricing to residential customers

Eni s Gas & Power segment is exposed to regulatory risks mainly in its domestic market in Italy. Developments in the regulatory framework may negatively affect future sales margins of gas and electricity, operating results and cash flow. Below is provided an overview of the most important aspects of the ongoing regulatory framework of the gas sector in Italy including management s evaluation of the possible impacts on the future results of operations in the Gas & Power segment.

The Italian Authority for Electricity and Gas (the "Authority") is entrusted with certain powers in the matter of natural gas pricing. Specifically, the Authority retains a surveillance power on pricing in the natural gas market in Italy and the power to establish selling tariffs for the supply of natural gas to residential users. Accordingly, decisions of the Authority on these matters may limit the ability of Eni to pass an increase in the cost of the raw material onto final consumers of natural gas.

In 2013, the Authority changed the pricing mechanism of gas supplies to retail customers by introducing a full indexation of the raw material cost component of the tariff to spot prices, by this way replacing the former oil-linked indexation. The new regulatory regime was introduced in a market scenario where gas spot prices were significantly lower than gas prices under long-term, oil-linked contracts, as the Brent price at the time was about 100 $/BBL. Subsequently, the Authority introduced a compensation mechanism to promote the renegotiation of long-term gas supply contracts. This compensation mechanism was intended to mitigate the impact of the new tariff regime to operators with long-term supply contracts (typically oil-linked) by reimbursing to them part of the higher long term gas supply costs which would be no longer recoverable trough tariffs. This compensation mechanism applies to the three thermal years, from October 2013 through October 2016.

The Authority set the initial amount of the compensation in 2013 based on the documentation filed by each operator, taking into account the price differential between the average price of a basket of theoretically efficient long-term contract and spot prices at the Dutch platform TTF. The Authority elaborated a projection of the supply costs of gas that Eni would incur in the future thermal year of the compensation mechanism, under various oil prices assumptions. Based on those projections and on gas forward prices and volume forecast for Eni, the Authority established a maximum compensation of euro 160 million, to which Eni would be entitled for the three-thermal year period of the mechanism implementation. The Authority resolution envisages that 40% of the compensation is due in the first thermal year, 40% in the second year and 20% in the third thermal year. In each thermal year, the Authority would update the compensation mechanism to verify the ongoing right of gas operators to receive compensation in the light of evolving trends in costs and prices of gas. Based on this, the initial amount of the compensation would be confirmed or, in case trends in spot prices vs. oil-linked prices reverse, operator would have to compensate customers by paying to the Authority up to three time the amount of the initial compensation, plus giving back any tranche of the compensation already cashed in.

In thermal year 2014, the Authority updated the index of supply costs applicable to Eni s portfolio. Under a 100 $/BBL scenario, the AEEGSI verified that Eni s costs of supplies were higher than spot prices and accordingly ratified the first tranche of the compensation equal to euro 60 million (or the 40% of the initial amount). This gain was recognized in the group consolidated financial statements for the year 2014. In November 2015, the Authority updated the index of procurement cost for thermal year 2015 and resolved that Eni s supply costs have evolved coherently to the Authority projections made in 2013. Under this scenario, the Authority confirmed the initial amount of the compensation of euro 160 million and Eni recognized a second tranche equal to 40% of that amount (approximately euro 60 million) in the 2015 Financial Statements.

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In spite of these favorable developments, considering the current market scenario, it is possible that the Authority might determine an unfavorable update of the supply cost index for the thermal year 2016. Under this scenario, Eni could incur a loss up to three times the amount of the initial compensation or euro 480 million, giving back the amounts already recognized in 2014 and 2015.

The final outcome is expected in the fourth quarter of 2016 when the AEEGSI is scheduled to update the supply cost index for the thermal year 2016, on which basis Eni is due to recognize the profit and loss impact (positive or negative as the case may be).

In the light of current market scenario, Eni prudently contested the Resolution 549/2014/R/gas, which implements the compensation mechanism. Eni claimed that the Resolution did not provided sufficient criteria for updating the compensation and could potentially determine unfair results, also contending its legitimacy.

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 about the impacts 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, as well as refining and other Group s 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&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 oil, natural gas, refining and other Group s operations.

Different kinds of limits and restrictions on the activities of exploring and producing hydrocarbons could be enacted also in OECD countries due to environmental reasons or other motivations as it would occur in case of a favorable outcome of an Italian referendum scheduled April 17, 2016 on whether to abrogate an environmental rule that currently allows oil&gas operators to continue production at offshore fields located in territorial waters beyond relevant concessions term till fields depletion. Eni is currently operating 29 concessions in Italy s territorial waters. These concessions account for approximately 1% of the Company s proved reserves at December 31, 2015 (6,890 mmBOE). Within such amount and factoring in the portion of those reserves that could be produced before the expirations of the underlying concessions, in case of an unfavorable outcome of the above mentioned referendum and assuming that those concessions would be revoked upon expiration, the Company s results of operations and cash flow might be negatively affected also considering the negative impact associated with higher amortization charges and accelerated wind down of decommissioning liabilities.

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.

Breach 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 on the workplace, health of employees, contractors and communities involved by the Company operations, including:

- costs to prevent, control, eliminate or reduce certain types of air and water emissions and handle waste and other hazardous materials, including the costs incurred in connection with government action to address climate change;
- remedial and clean-up measures related to environmental contamination or accidents at various sites, including those owned by third parties (see discussion below);

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- damage compensation claimed by individuals and entities, including local, regional or state administrations, in case Eni causes any kind of accident, pollution, contamination or other environmental liability involving 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 license 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:

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

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. Management believes that Eni adopts high operational standards to ensure safety in running its operations and safeguard of the environment and the health of employees, contractors and communities. In spite of those measures, it is possible that incidents like blowouts, oil spills, contaminations, pollution, and release in the air, soil and ground water of pollutants and other dangerous materials, liquids or gases, and other similar events could occur that would result in damage, also of large proportion and reach, to the environment, employees, contractors, communities and property. The occurrence of any such events could have a material adverse impact on the Group 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 requirements 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 damages, and other damages 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 held liable of violations of any environmental laws or regulations.

Eni is notified from time to time of potential liabilities at the Italian sites where the Company has conducted industrial operations in the past. These potential liabilities may arise from both historical Eni operations and the historical operations of companies that Eni has acquired. Many of those potential liabilities relate to certain industrial sites 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 locations Eni has commenced 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 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 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 sites to continue in the foreseeable future impacting Eni s liquidity. As of December 31, 2015, 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 liability.

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 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 46% of Eni s production in 2015 on available-for-sale basis.

In December 2015, a global climate agreement was reached in Paris at the 21st Conference of Parties organized by the United Nations under the Framework Convention on Climate Change. The agreement, which goes into effect in 2020, resulted in nearly 200 countries committing to work towards limiting global warming and agreeing to a monitoring and review process of GHG emissions. The agreement includes binding and non-binding elements and did not require ratification by countries. 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 (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 conserve 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. Likewise, such restrictions may result in additional compliance obligations with respect to the release, capture, sequestration, and use of carbon dioxide that 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 our equipment and operations could require us to incur costs to monitor and report on GHG emissions or install new equipment to reduce emissions of GHG associated with our operations.

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 as a result of climate change or otherwise, they could have an adverse effect on our 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 December 31, 2015 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 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 non-compliance with applicable laws and regulations, including non-compliance with anti-bribery and anticorruption 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.

Risks from acquisitions

Eni is constantly monitoring the oil&gas market in search of opportunities to acquire individual assets or companies with a view of achieving its growth targets or complementing its asset portfolio. Acquisitions entail an execution risk the risk that the acquirer will not be able to effectively integrate the purchased assets so as to achieve expected synergies. In addition, acquisitions entail a financial risk the risk of not being able to recover the purchase costs of acquired assets, in case a prolonged decline in the market prices of oil and natural gas occurs. Eni may also incur unanticipated costs or assume unexpected liabilities and losses in connection with companies or assets it acquires. If the integration and financial risks 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 loss of output, revenues, maintenance and repair expenses and cash flow shortfall.

Eni s crisis management systems may be ineffective and Eni may be the target of cyber attacks

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. Likewise, 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&gas reserves, volume of gas purchased under its long-term gas purchase contracts, which are not covered by contracted sales, its refining margins and other activities. The Group s risk management objectives in addressing commodity risk are to optimize the risk profile of its commercial activities by effectively managing economic margins and safeguarding the value of Eni assets. To achieve this, Eni engages in risk management activities seeking both to hedge Group s exposures and to profit from short-term market opportunities and trading.

Eni is engaged in substantial trading and commercial activities in the physical markets. Eni also uses financial instruments such as futures, options, Over The Counter (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 risks.

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 and Risk Management 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.

Commodity risk

Commodity risk is the risk associated with fluctuations in the price of commodities which may impact the Group s results of operations and cash flow. Exposure to commodity risk is both of a strategic and commercial nature. Generally, the Group does not hedge its strategic exposure to commodity risk. However, the Group actively manages its exposure to commercial risk arising when a contractual sale of a commodity has occurred or it is highly probable that it will occur and the Group aims to lock in the associated commercial margin.

The Group s risk management policies have evolved particularly in response to the deep changes occurred in the competitive landscape of the gas marketing business, volatile gas margins and development of liquid markets to trade spot gas. These policies also contemplate the use of derivative contracts for speculative purposes whereby Eni is seeking to profit from opportunities available in the gas market based, among other things, on its expectations regarding trends in future prices.

As part of those trading activities, the Company is implementing strategies of asset-backed trading in order to maximize the economic value of the flexibilities associated with its assets. Management believes that the price risks related to asset-backed trading activities are mitigated by the natural hedge granted by the assets availability.

These derivative contracts entered into for trading purposes may lead to gains, as well as losses, which, in each case, may be significant. Those derivatives are accounted for through profit and loss, resulting in higher volatility in Eni s earnings.

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 U.S. 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. In 2015, the Exploration & Production results of operations were positively affected by trends in the exchange rate of the euro against the U.S. dollar as the euro depreciated on average by 16.5% against the U.S. dollar.

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

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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 an ongoing slump in commodity prices. If there are 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&gas industry is capital intensive. Eni makes and expect to continue to make substantial capital expenditures in its business for the exploration, development, exploitation and production of oil and natural gas reserves. In 2015, we invested approximately euro 10.2 billion in our Exploration & Production segment, down by approximately 17% from 2014 at constant exchange rates, in response to weak oil prices. Our capital budget for the four-year plan 2016-2019 amounts euro 37 billion, excluding capex associated with our disposal plan, and is substantially lower than our previous industrial plan (down by an estimated 21% at constant exchange rates) as a result of a planned reduction in spending prompted by significantly depressed commodity prices. This capital plan is directed for about 90% to the E&P segment. We have budgeted euro 9.4 billion for capital expenditure in 2016 relating to continuing operations which are 20% lower than in 2015 at constant exchange rates. We may find that additional reductions in our 2016 capital spending become necessary depending on market conditions.

Historically, Eni s capital expenditures have been financed with cash generated by operations, proceeds from asset disposal, 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 others, changes in commodity prices, available cash flows, lack of access to capital, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of transportation capacity, and regulatory, technological and competitive developments.

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

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

If revenues or Eni s ability to borrow decrease significantly due to factors like 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 disposal, or cash available under Eni s liquidity reserve 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 2016-2019 business plan in particular, management expects to deliver approximately euro 7 billion of additional cash flows from asset disposals, the main part of which will comprise the divestment of stakes in our exploration assets thereby in essence monetizing some of the Group s recent exploration successes and reserves. These additional cash flows are intended to provide funding to support organic growth and our planned shareholders distributions in a manner consistent with our target capital structure. The Company is seeking to complete such disposals in large part within 2016-2017. However, asset disposals are subject to execution risk and may fail to be completed, and the proceeds received from such disposals may not reflect values 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 our financial targets forcing us to either curtail capital expenditure thus hampering growth or take on more finance debt.

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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 arise from the 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 higher than normal level of counterparty default 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 our upstream projects for exploring and developing hydrocarbons. In Eni s 2015 Consolidated Financial Statements, it was accrued an allowance against doubtful accounts amounting to euro 581 million (compared to euro 518 million in 2014), mainly relating to the Gas & Power business. Management believes that this business is particularly exposed to credit risks due to its large and diversified customer base, which include 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 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.

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 due to negligence, Eni could be adversely affected by, among other things, loss or damage of intellectual property, proprietary information, or customer data, having Eni s business operations interrupted, 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.

The Company s auditors, like all other independent registered public accounting firms operating in Italy, are not permitted to be subject to inspection by the Public Company Accounting Oversight Board, and accordingly, investors may be deprived of the benefits of such inspection

The independent registered public accounting firm that issues the audit reports included in Eni s annual reports filed with the U.S. SEC, as auditor of companies that are traded publicly in the United States and firms registered with the

Public Company Accounting Oversight Board ("PCAOB"), is required by the laws of the United States to undergo regular inspections by the PCAOB to assess its compliance with U.S. SEC rules and PCAOB professional standards.

Because Eni s auditor is a registered public accounting firm in Italy, a jurisdiction where the PCAOB is currently unable under Italian law to conduct inspections pending the mutual agreement between the PCAOB and the Italian Authorities, Eni s auditor, like all other independent registered public accounting firms in Italy, is currently out of the reach of PCAOB inspections. PCAOB inspections of audit firms have identified holes and deficiencies in those firms audit procedures and quality control procedures, which may be addressed as part of the inspection process to improve future audit quality. The lack of PCAOB inspections in Italy prevents the PCAOB from regularly evaluating Eni s auditor s audits and quality control procedures. As a result, the inability of the PCAOB to conduct inspections of auditors in Italy may deprive Eni s investors of the benefits of PCAOB inspections.

Item 4. INFORMATION ON THE COMPANY

History and development of the Company

Eni SpA with its consolidated subsidiaries of the continuing operations engages in oil&gas exploration, development and production, marketing of gas, electricity and LNG, power generation, refining and marketing of petroleum products and, commodity trading. In 2015, the Group commenced a plan to divest its Engineering & Construction segment, which is managed by the subsidiary Saipem (Eni s interest being 42.9%), and its Chemical business which is managed by Eni s wholly-owned subsidiary Versalis. In the 2015 Consolidated Financial Statements, the two segments have been accounted for in accordance with IFRS 5 "non-current assets held for sale and discontinued operations". Therefore, they have been disclosed as discontinued operations and have been measured at the lower of their carrying amounts and fair value; results of operations and cash flow of the comparative periods have been restated accordingly. Eni has operations in 66 countries and 29,053 employees (excluding Saipem and Versalis) as of December 31, 2015.

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.

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
The name of the agent of Eni in the United States is Pasquale Salzano, 485 Madison Avenue, New York, NY 10002.

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 42 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Ghana and Mozambique. In 2015, Eni average daily production amounted to 1,688 KBOE/d on an available-for-sale basis. As of December 31, 2015, Eni s total proved reserves amounted to 6,890 mmBOE; proved reserves of subsidiaries totaled 5,975 mmBOE; Eni s share of reserves of equity-accounted entities stood to 915 mmBOE. In 2015, Eni s Exploration & Production segment reported net sales from operations (including inter-segment sales) of euro 21,436 million and an operating loss of euro 144 million.

Eni s Gas & Power segment engages in supply, trading and marketing of gas and electricity, international gas transport activities, and LNG supply and marketing. This segment also includes the activity of electricity generation that is ancillary to the marketing of electricity. In 2015, Eni s worldwide sales of natural gas amounted to 90.88 BCM. Sales in Italy amounted to 38.44 BCM, while sales in European markets were 52.44 BCM which included 4.61 BCM of gas sold to certain importers to Italy. Eni produces power at a number of operated sites in Italy with a total installed capacity of 4.9 GW as of December 31, 2015. In 2015, electricity sold totaled 34.88 TWh. In 2015, Eni s Gas & Power segment reported net sales from operations (including inter-segment sales) of euro 52,096 million and an operating loss of euro 1,258 million. 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. The objective of this activity is both to hedge part of the Group exposure to the commodity risk and to optimize commercial margins by entering speculative derivative transactions. Since 2015, of the Gas & Power segment also comprises the result of activities of crude oil and products supply, trading and shipping services provided on behalf of Group companies, which were formerly reported in the Refining & Marketing segment (see Item 5). Previous reporting periods data have been restated accordingly.

Eni s Refining & Marketing segment engages in crude oil supply and refining and petroleum products marketing in retail and wholesale markets mainly in Italy and in the rest of Europe. In 2015, processed volumes of crude oil and other feedstock amounted to 26.41 mmtonnes and sales of refined products were 35.24 mmtonnes, of which 26.53 mmtonnes in Italy. Retail sales of refined products at Eni s service stations amounted to 8.89 mmtonnes in Italy and in the rest of Europe. In 2015, Eni s retail market share in Italy through its "Eni" branded network of service stations was

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24.5%. In 2015, Eni s Refining & Marketing segment reported net sales from operations (including inter-segment sales) of euro 18,458 million and operating loss of euro 552 million.

A list of Eni s subsidiaries is provided in "Item 18 note 46 Other information about investments of the Notes on Consolidated Financial Statements".

Strategy

In order to manage a sharply deteriorated commodity price environment, the Company outlined for the next four-year period an action plan, which comprises a number of rigorous initiatives and objectives in order to mitigate the impact of lower oil prices on results and cash flow and to preserve the Group financial structure, particularly in the short to medium term. Our financial projections for the four-year plan 2016-2019 and capital project evaluations are based on the assumption of a long-term Brent reference price of 65 $/BBL that is significantly lower than our previous long-term price assumption of 90 $/BBL. Our new long-term price assumption is reflective of our view of worsened market fundamentals driven by continued oversupplies and uncertainties about the pace of energy demand growth in the long term. We are forecasting a Brent price of 40 $/BBL in 2016 and a progressive recovery along the plan period up to the long term case of 65 $/BBL due to an expected better balance between supply and demand in the light of reduced capital expenditure plans by oil majors, the possible exit from the market of producers with unsustainable cost structure and any possible agreements on part of producing countries to curb output.

Against the backdrop of a depressed commodity price environment in the short to medium term, our primary target remains to generate adequate cash flow from operations which will be underpinned by well-designed industrial actions, capital discipline, focus on Exploration & Production activities and a large disposal plan.

In particular, our strategic guidelines could be articulated along different time horizons:

- in the near-term, we will seek to maximize cash-flow generation in order to preserve the company s financial structure by increasing efficiency programs, and by modulating and re-phasing capital expenditures;
- in the medium-term, we will focus on capital discipline to develop our portfolio of hydrocarbons resources which we believe offer us many options to profitably grow production due to the low break-even price of our new projects, also targeting to maintain a strong reserve replacement ratio; and
- in the long-term, we intend to lie the foundation to adapt our business model to a competitive landscape where oil companies will be required to reduce significantly GHG emissions.

In approving the capital expenditure plan for the 2016-2019 period the Company identified actions designed to reconfigure and re-phase long-term projects and to reduce the costs of the supply of upstream plants and facilities and other field services by renegotiating contracts leveraging on the deflationary pressure induced by low oil prices. This optimization will result in euro 37 billion capital expenditures in the next four years net of the capex associated with the disposal plan, down by approximately 21% compared to the previous plan, at constant exchange rates. The disposal plan, amounting to approximately euro 7 billion in the 2016-2019 period, is based on the dilution of our working interests in certain promising exploration assets and will provide additional financial flexibility. The Company forecasts that the planned industrial actions, the reduction in expenditures and the disposal plan will enable Eni to preserve its financial structure during the worst phase of the oil downturn, targeting to maintain the leverage below the threshold of 0.3 throughout the oil cycle. In projecting our cash flows and cash requirement we planned to confirm the current level of our cash dividend. See "Item 5 Management s expectations of operations".

In the Exploration & Production segment we plan to preserve cash generation in a low oil price environment. To achieve this objective we plan the following strategic actions: (i) focus on near-field exploration reducing expenditures; (ii) fast track development of discovered resources through the optimization of the time to market and strict control of project execution; (iii) monetization of interests in discoveries made; (iv) production growth at an average rate higher than 3% across the plan period, maintaining a solid base of long plateau/long-term cash flow projects; (v) modular approach and phased project development in order to reduce capital expenditure exposure and fasten production start-up; and (vi) increased efficiency through a wide range of actions aimed at reducing operating costs, pursued also through the renegotiations of supply contracts.

In the Gas & Power segment we are seeking to preserve the economic and financial sustainability in the long term against the backdrop of structural headwinds in the European gas sector where we do not expect significant improvement due to continued weak demand, strong competition and oversupplies which will affect sale prices and margins. Our strategy will be driven by the renegotiation of our entire portfolio of long-term supply contracts in order to align our cost position to prevailing market conditions. The consolidation of profitability and cash generation will be helped by streamlining operations optimizating logistic costs focusing on the development and growth in value added segments (retail sales of gas and electricity, LNG, trading), and in the medium term, exploiting synergies in connection with better monetization of equity gas in international markets thanks to our knowledge in trading.

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Our priority in the Refining & Marketing segment is to strengthen profitability and cash generation even in a depressed downstream oil environment. We plan to lower our break-even refining margin, maintaining the current refining capacity, leveraging on optimizations in existing plants (increasing the conversion capacity of our refineries in order to process low-quality crudes), the ramp-up of Venice green refinery and the completion of a new green refinery in Gela, while maintaining a strong focus on efficiency. In the marketing business in Italy we will enhance profitability leveraging on innovation of products and services, as well as on efficiency. Outside Italy, Eni plans to grow selectively in target European markets (Germany, Austria, Switzerland and France).

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

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".

2015 disposal activity

In the last months of 2015, Eni carried out a complex transaction to restructure the share ownership of its listed subsidiary Saipem through a transaction involving a new shareholder, Fondo Strategico Italiano (FSI), an entity controlled by the Italian Minister of Economy and Finance, which also included the reimbursement of intercompany loans owed by Saipem to Eni. The transaction was in line with the Group strategy aimed to:

1. focus on Group s upstream core business, by making available additional financial sources to be reinvested in the development of oil&gas reserves; and
2. strengthen the Group capital structure on the back of the weak oil scenario.

On January 22, 2016, following the satisfaction of all the conditions precedent, among which the consensus of Consob to the share capital increase resolved by Saipem, Eni closed the Sale and Purchase Agreement regarding the sale of 12.503% of the share capital of Saipem to the Fondo Strategico Italiano (FSI). The transaction refers to No. 55,176,364 Saipem shares at an average price of euro 8.39 per share for a total consideration of euro 463 million. The reference price for the transaction was determined as the arithmetic average of the official prices of the Saipem shares recorded in the trading days immediately before and after the announcement to the markets of the transaction, on October 28, 2015. The total consideration has been paid by FSI in a single installment, at closing.

At the closing of the Sale and Purchase Agreement, the preliminary Shareholders Agreement signed by Eni and FSI on October 27, 2015 became effective. The Agreement establishes the terms and conditions that shall govern, from the closing date onwards, the two parties respective relationships as shareholders of Saipem, particularly with reference to the entity corporate governance and any possible transaction relating each party s interest in Saipem.

Each of Eni and FSI are contributing to the Shareholders Agreement an equal number of Saipem shares not exceeding 12.503% of the Company s ordinary share capital (therefore up to a total amount slightly above 25% of Saipem ordinary share capital). The Shareholders Agreement which entered into force on the closing date has a three-year term, with automatic renewal for a further period of three years, unless terminated by notice.

The key elements of the Shareholders Agreement provides, inter alia: (a) for the future renewal of corporate bodies, the submission by Eni and FSI of a single list for the appointment of the board of directors (where the President and the CEO will be designated jointly by the parties) and the panel of statutory auditors of Saipem and the relevant vote commitments; (b) mutual commitments to stand-still and lock-up commitment on all the shares contributed to the

Shareholders Agreement, and certain other restriction regarding the transfer of shares not contributed to the Shareholders Agreement; and (c) obligations to engage in consultation before exercising voting rights and, to the extent permitted by law, voting commitments (also regarding Saipem shares not contributed to the Shareholders Agreement) in relation to all resolutions submitted to the shareholders meetings of Saipem and certain resolutions of Saipem s Board of Directors that are conventionally considered relevant, among which the approval of the industrial plan.

Based on the new corporate governance setup of Saipem, Eni and FSI have joint control of Saipem.

Finally Eni and FSI committed towards Saipem to subscribe pro-rata the share capital increase resolved by the entity for euro 3.5 billion.

The agreements provides the reimbursement of intercompany financing receivables owed by Saipem to Eni through the proceeds of the share capital increase and the refinancing with certain third-party financing institutions.

Considering that the transactions disclosed above were closed after the 2015 reporting date, in Eni s Consolidated Financial Statements for the year 2015 Saipem is still fully consolidated and presented as "discontinued operation" based on the guidelines of IFRS 5 on disposal assets. Therefore, effective for the full year, Saipem revenues and expenses and cash flow have been classified as discontinued operations and its assets and liabilities have been classified as held for sale. In addition, Eni s net assets in Saipem have been aligned to the lower of their carrying amount and their fair value given by Saipem share price at the reporting date (euro 7.49 per share) (see "Item 5" for further information).

Therefore, the economic and financial impacts of the Saipem transaction will be recorded in Eni 2016 accounts, as described below:

- considering that the corporate governance of Saipem as defined in the Shareholders Agreement has established joint control over the entity, Eni is set to derecognise the former subsidiary s asset and liabilities, revenues and expenses, effective January 22, 2016. The residual stake in Saipem of 30.42% will be recognized as an investment in an equity-accounted joint venture with initial carrying amount aligned to Saipem share price at the closing date of the transaction (euro 4.2 per share) equal to an overall value of euro 564 million and a loss to be recognized through profit and loss of euro 441 million (resulting from the difference between the fair value on the closing date and the book value at December 31, 2015). This loss will be recognized in the Group consolidated accounts for the first quarter 2016 as part of gains and losses of the discontinued operations. Considering the pro-quota subscription of Saipem s share capital increase, the book value of Eni s residual interest in the former subsidiary currently amounts to euro 1,614 million;
- a reduction of euro 4.8 billion in net borrowings resulting from the reimbursement by Saipem to Eni of intercompany financing receivables (euro 5.4 billion as of December 31, 2015), the proceeds from the disposal of Eni s stake (euro 0.4 billion), net of the amount cashed out to subscribe Saipem share capital increase (euro 1.07 billion); and
- assuming the effects of the transaction at December 31, 2015, the Group leverage would improve significantly.

At the end of February 2016, following completion of the subscription of the share capital increase and assumption by Saipem of third-party refinancing, Saipem reimbursed intercompany loans owed to Eni.

As of the date of the transaction agreement, Eni is subjected to the de facto control of the MEF (Italian Ministry of Economy and Finance). FSI is also indirectly controlled by MEF. Therefore the transaction is a transaction between Eni and one of its related parties. In executing this transaction Eni has complied with all relevant applicable listing standards, market regulation and internal procedures set to ensure fairness and formal and substantial correctness of the transaction as well as the fact that the transaction was in the best interest of the Company.

In 2015, the Group commenced a plan to reduce its exposure to the Chemical business managed by Eni s wholly-owned subsidiary Versalis SpA. At the reporting date negotiations were underway to define an agreement with an industrial partner who, by acquiring a controlling stake of Versalis, would support Eni in implementing the industrial plan designed to upgrade this business.

Therefore, effective for the full year, like Saipem, Versalis revenues and expenses and cash flow have been classified as discontinued operations and its assets and liabilities have been classified as held for sale. In addition, Eni s net assets in Versalis have been aligned to the lower of their carrying amount and their fair value based on the proposal transaction. See "Item 5 Discontinued operations".

Other significant business and portfolio developments

The significant business and portfolio developments that occurred in 2015 and to date in 2016 were the following:

In March 2016, Eni was awarded the operatorship of the exploration license Cape Three Points Block 4 (Eni s interest 42.47%), located in the offshore of Ghana.

In March 2016, Eni signed a Farm-Out Agreement (FOA) with Chariot Oil & Gas that includes the operatorship to Eni and a 40% stake enter into Rabat Deep Offshore exploration permits I-VI offshore Morocco. The completion of this FOA is subject to the authorization of the Moroccan Authorities, to current partners approval and other conditions precedent.

In March 2016, production was started up at the Goliat field, located within the Production License 229, off Norway. Goliat, the first oil field to start production in the Barents Sea, was developed through the floating cylindrical production and storage vessel (FPSO). The Unit has a capacity of 1 million barrels of oil. The daily output will reach 100,000 BOE/d (65,000 BOE/d net to Eni).

In February 2016, Mozambique Authorities sanctioned the development of the first development phase of Coral, targeting to put into production 5 TCF of gas.

In December 2015, in Mozambique, following the signing of the Unitization and Unit Operating Agreement (UUOA) and in full agreement with all the concessionaries of the projects, a unitization was set out for the development of the natural gas reservoirs straddling Areas 4 (operated by Eni) and 1 (operated by Anadarko) in the Rovuma Basin, offshore Mozambique. In accordance with the UUOA, the development of the straddling reservoirs will be carried out at an early stage in a separated but coordinated way by the two operators. Future developments will be jointly pursued by Area 4 and Area 1 concessionaires. The Final Investment Decision relating the Mamba field in Eni s operating Area is expected in 2017.

In December 2015, Eni entered Mexico s upstream sector by signing the Production Sharing Contract as operator (Eni s interest 100%) of Block 1 to develop the oilfields of Amoca, Miztón e Tecoalli. The delineation campaign of the fields was submitted to the Mexican Authorities in the first quarter of 2016 and plans the drilling of four wells in order to define a fast track and synergic development plan.

In August 2015, Eni made a large discovery at the Zohr exploration prospect in the deep waters of the Egyptian section of the Mediterranean Sea. Based on ongoing studies management considers that this discovery contains a large amount of gas resources.

In July 2015, Eni started production at the Perla gas field, offshore Venezuela. Perla is one of Eni s most important start-ups of 2015 and has been developed in just 5 years, an industry leading time-to-market. A production plateau is expected at approximately 1,200 mmCF/d. Gas is sold to the national oil&gas company PDVSA under a Gas Sales Agreement running until 2036.

In June 2015:

- Eni signed a preliminary agreement with KazMunayGas to acquire 50% of the mineral rights in the Isatay block in the Caspian Sea; and
- Eni signed an agreement to supply 1.4 mmtonnes/y of LNG from the Eni-operated Jangkrik field (Eni s interest 55%) to the Indonesian state-run company PT Pertamina, effective in 2017. The agreement will support the development of the Jangkrik field.

In March 2015, Eni has finalized a strategic oil agreement in Egypt, which provides investment of up to $5 billion (at 100%) to develop the Egypt s oil&gas reserves in future years. Eni has also agreed on new terms for ongoing oil contracts, with the economic effects retroactive to January 1, 2015. Set new measures to reduce overdue amounts of trade receivables relating to hydrocarbon supplies to Egyptian State-owned companies.

In January 2015, Eni sanctioned the final investment decision for the integrated Offshore Cape Three Points (OCTP) oil&gas project (Eni 47.22%, operator), in Ghana. The first oil is expected in 2017.

In 2015, in addition to the large Zohr discovery, the main discoveries were made: (i) in the prospect Nkala Marine in the Marine XII block in Congo; (ii) in Egypt, with a gas and condensates discovery in the Noroos prospect in the West Abu Madi license, which has entered production in just two months and the Melehia West Deep discovery in the Western Egyptian Desert; (iii) in Libya, in the contractual area D with a gas and condensates discovery; and (iv) in Indonesia, in the Merakes field.

In addition, Eni closed the following transactions:

- in January 2016, Eni received reimbursement of the bonds exchangeable into ordinary shares of Snam, through the receipt of approximately 288 million shares equal to approximately 8.22% of the share capital of the company. Eni holds a residual interest of the 0.03% of Snam share capital; and
- in November 2015, Eni completed the sale of a residual 4% interest in Galp with proceeds of euro 325 million at a price of euro 9.81 per share. The transaction was carried out through an accelerated book-building procedure aimed at institutional investors.

In 2015, capital expenditures of continuing operations amounted to euro 10,775 million, entirely relating to Exploration & Production, Gas & Power and Refining & Marketing segments, and primarily related to: (i) development of oil and gas reserves (euro 9,341 million) deployed mainly in Angola, Norway, Egypt, Kazakhstan, Congo, Indonesia, Italy and the United States, and exploratory projects (euro 820 million) carried out primarily in Egypt, Libya, Cyprus, Gabon, Congo, the United States, the United Kingdom and Indonesia; (ii) refining, supply and logistics in Italy and outside Italy (euro 282 million) with projects designed to improve the conversion rate and flexibility of refineries, as well as the upgrade of the refined product retail network in Italy and in the rest of Europe (euro 126 million); and (iii) initiatives to upgrade combined-cycle power plants (euro 69 million).

In 2014, capital expenditures of continuing operations amounted to euro 11,264 million and primarily related to: (i) development of oil&gas reserves (euro 9,021 million) deployed mainly in Norway, Angola, Congo, the United States, Italy, Nigeria, Egypt, Indonesia and Kazakhstan and exploratory projects (euro 1,398 million) carried out primarily in Libya, Mozambique, the United States, Nigeria, Angola, Indonesia, Cyprus, Norway and Gabon; (ii) refining, supply and logistics in Italy and outside Italy (euro 362 million) with projects designed to improve the conversion rate and flexibility of refineries, as well as the upgrade of the refined product retail network in Italy and in the rest of Europe (euro 175 million); and (iii) initiatives to improve flexibility of the combined-cycle power plants (euro 98 million).

In 2013, capital expenditures of continuing operations amounted to euro 11,584 million, and primarily related to: (i) development of oil&gas reserves (euro 8,580 million) deployed mainly in Norway, the United States, Angola, Congo, Italy, Nigeria, Kazakhstan, Egypt and the United Kingdom, and exploration projects (euro 1,669 million) carried out mainly in Mozambique, Norway, Congo, Togo, Nigeria, the United States and Angola; (ii) refining, supply and logistics in Italy and outside Italy (euro 462 million) with projects designed to improve the conversion rate and flexibility of refineries, in particular at the Sannazzaro refinery, as well as the upgrade of the refined product retail network in Italy and in the rest of Europe (euro 210 million); and (iii) initiatives to improve flexibility of the combined-cycle power plants (euro 119 million).

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 42 countries, including Italy, Libya, Egypt, Norway, the United Kingdom, Angola, Congo, Nigeria, the United States, Kazakhstan, Algeria, Australia, Venezuela, Iraq, Ghana and Mozambique. In 2015, Eni average daily production amounted to 1,688 KBOE/d on an available-for-sale basis. As of December 31, 2015, Eni s total proved reserves amounted to 6,890 mmBOE; proved reserves of subsidiaries totaled 5,975 mmBOE; Eni s share of reserves of equity-accounted entities stood to 915 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 more than 3% on average in the next 2016-2019 four-year period. Our production plans are incorporating our Brent price scenario of 40 $/BBL in 2016 and a gradual recovery in the subsequent years up to our long-term case of 65 $/BBL in 2019 and going forwards (on constant monetary term compared to 2019, i.e. from 2020 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, Barents Sea, Kazakhstan, and the Far East, leveraging Eni s vast knowledge of reservoirs and geological basins, as well as technical and producing synergies. Planned start-ups over the next four years will add more than 800 KBOE/d of new production by 2019; over 90% of these new projects have already been sanctioned and 90% operated.

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 euro 37 billion to explore for and to develop reserves over the next four years, with a decrease of 18% net of exchange rate effects versus the previous four-year plan to mitigate the impact of a low oil price environment. We plan to prioritize lower intensity projects, brown-field developments and infilling wells mainly in Congo, Angola and Egypt, 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.

Exploration projects will attract some euro 3.5 billion with a reduction of 37% net of exchange rate effects in 2016 and 28% over the plan period. Exploration expenditure will be focused on proven plays, near field and appraisal exploration, where we plan to drill 80% of our scheduled wells. The most important amounts of exploration expenditure will be incurred in 2018.

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 these initiatives we believe that almost all of our project which we are currently developing over the next four years plan will be completed on time and on cost schedule.

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; (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.

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For the year 2016, management plans to spend over euro 8.6 billion in reserves development and exploration projects.

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.

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.

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(1) See "Item 19 Exhibits" in the Annual Report on Form 20-F 2009.

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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 2015, Ryder Scott Company, DeGolyer and MacNaughton and Gaffney, Cline & Associates provided an independent evaluation of approximately 31% of Eni s total proved reserves at December 31, 2015[4], confirming, as in previous years, the reasonableness of Eni internal evaluation[5].

In the 2013-2015 three-year period, 86% of Eni total proved reserves were subject to an independent evaluation. As at December 31, 2015, the main Eni properties not subjected to independent evaluation in the last three years were Kashagan (Kazakhstan) and CAFC-MLE (Algeria).

(2) From 1991 to 2002, DeGolyer and MacNaughton; from 2003, also Ryder Scott and in 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, 2015, 2014 and 2013. Net proved reserves are set out in more detail under the heading "Supplemental oil and gas information" on page F-139.

HYDROCARBONS (mmBOE)	**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total reserves**
Consolidated subsidiaries									
Year ended Dec. 31, 2013	**499**	**557**	**1,783**	**1,155**	**1,035**	**263**	**240**	**176**	**5,708**
developed	408	343	1,003	701	566	90	153	123	3,387
undeveloped	91	214	780	454	469	173	87	53	2,321
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
Equity-accounted entities									
Year ended Dec. 31, 2013			**19**	**75**		**7**	**726**		**827**
developed			19			3	18		40
undeveloped				75		4	708		787
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
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2013	**499**	**557**	**1,802**	**1,230**	**1,035**	**270**	**966**	**176**	**6,535**
developed	408	343	1,022	701	566	93	171	123	3,427
undeveloped	91	214	780	529	469	177	795	53	3,108
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

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LIQUIDS (mmBBL)	**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total reserves**
Consolidated subsidiaries									
Year ended Dec. 31, 2013	**220**	**330**	**830**	**723**	**679**	**128**	**147**	**22**	**3,079**
developed	177	179	561	465	295	38	96	20	1,831
undeveloped	43	151	269	258	384	90	51	2	1,248
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
Equity-accounted entities									
Year ended Dec. 31, 2013			**16**	**15**		**1**	**116**		**148**
developed			16				19		35
undeveloped				15		1	97		113
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
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2013	**220**	**330**	**846**	**738**	**679**	**129**	**263**	**22**	**3,227**
developed	177	179	577	465	295	38	115	20	1,866
undeveloped	43	151	269	273	384	91	148	2	1,361
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

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NATURAL GAS (BCF)	Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total reserves
Consolidated subsidiaries									
Year ended Dec. 31, 2013	**1,532**	**1,247**	**5,231**	**2,374**	**1,957**	**744**	**509**	**848**	**14,442**
developed	1,266	904	2,432	1,295	1,488	286	310	561	8,542
undeveloped	266	343	2,799	1,079	469	458	199	287	5,900
Year ended Dec. 31, 2014	**1,432**	**1,171**	**5,291**	**2,744**	**2,049**	**846**	**468**	**807**	**14,808**
developed	1,192	887	2,110	1,271	1,553	261	393	675	8,342
undeveloped	240	284	3,181	1,473	496	585	75	132	6,466
Year ended Dec. 31, 2015	**1,304**	**1,044**	**4,798**	**2,714**	**2,354**	**878**	**439**	**771**	**14,302**
developed	1,051	919	2,566	1,390	1,830	185	373	585	8,899
undeveloped	253	125	2,232	1,324	524	693	66	186	5,403
Equity-accounted entities									
Year ended Dec. 31, 2013			**15**	**330**		**28**	**3,353**		**3,726**
developed			15			14	5		34
undeveloped				330		14	3,348		3,692
Year ended Dec. 31, 2014			**15**	**351**		**18**	**3,353**		**3,737**
developed			15	89		10	6		120
undeveloped				262		8	3,347		3,617
Year ended Dec. 31, 2015			**13**	**387**		**12**	**3,581**		**3,993**
developed			13	85		9	1,295		1,402
undeveloped				302		3	2,286		2,591
Consolidated subsidiaries and equity-accounted entities									
Year ended Dec. 31, 2013	**1,532**	**1,247**	**5,246**	**2,704**	**1,957**	**772**	**3,862**	**848**	**18,168**
developed	1,266	904	2,447	1,295	1,488	300	315	561	8,576
undeveloped	266	343	2,799	1,409	469	472	3,547	287	9,592
Year ended Dec. 31, 2014	**1,432**	**1,171**	**5,306**	**3,095**	**2,049**	**864**	**3,821**	**807**	**18,545**
developed	1,192	887	2,125	1,360	1,553	271	399	675	8,462
undeveloped	240	284	3,181	1,735	496	593	3,422	132	10,083
Year ended Dec. 31, 2015	**1,304**	**1,044**	**4,811**	**3,101**	**2,354**	**890**	**4,020**	**771**	**18,295**
developed	1,051	919	2,579	1,475	1,830	194	1,668	585	10,301
undeveloped	253	125	2,232	1,626	524	696	2,352	186	7,994

Volumes of oil and natural gas applicable to long-term supply agreements with foreign governments in mineral assets where Eni is operator totaled 139 mmBOE as of December 31, 2015 (282 and 536 mmBOE as of December 31, 2014 and 2013, respectively). Said volumes are not included in reserves volumes shown in the table herein.

	Subsidiaries			Equity-accounted entities		
	2013	2014	2015	2013	2014	2015
	(mmBOE)					
Additions to proved reserves	621	643	849		11	98
Purchases of minerals-in-place	4	4				
Sales of minerals-in-place	(13)	(8)	(17)	(652)		
Production for the year [(a)]	(571)	(575)	(629)	(20)	(8)	(13)

(a) The difference over production sold of 642.4 mmBOE (555.3 mmBOE in 2013 and 549.5 mmBOE in 2014) reflected natural gas volumes of 26.4 mmBOE consumed in operations (30 mmBOE in 2013 and 29.4 mmBOE in 2014), changes in inventories and other factors.

	Subsidiaries and equity-accounted entities		
	2013	2014	2015
		(%)	
Proved reserves replacement ratio of subsidiaries and equity-accounted entities, all sources	(7)	112	145

Eni s proved reserves as of December 31, 2015 totaled 6,890 mmBOE (liquids 3,559 mmBBL; natural gas 18,295 BCF). Eni s proved reserves reported an increase of 288 mmBOE, or 4.4%, from December 31, 2014. All sources additions to proved reserves booked in 2015 were 947 mmBOE; of which 849 mmBOE came from Eni s subsidiaries and 98 mmBOE from Eni s share of equity-accounted entities.

Price effects were globally positive, leading to an upward revision of 278 mmBOE, due to higher volume entitlements at our PSA contracts because of the cost recovery mechanism reflecting a lowered Brent price used in the reserve estimation process down to 54 $/BBL in 2015 compared to 101 $/BBL in 2014, which was marginally offset by our having to remove certain volumes of reserves which have become uneconomical in that environment. Further information about how to determine year-end amounts of proved reserves and the relevant net present value is provided in "Item 3 Risk factors Risk associated with the exploration and production of oil and natural gas".

The methods (or technologies) used in the Eni s proved reserves assessment in 2015 depend on stage of development, quality and completeness of data, and production history availability. The methods include volumetric estimates, analogies, reservoir modelling, decline curve analysis or a combination of such methods. The data considered for these analyses are obtained from a combination of reliable technologies that produce consistent and repeatable results including well or field measurements (i.e. logs, core samples, pressure information, fluid samples, production test data and performance data) and indirect measurements (i.e. seismic data). However for each reservoir assessment the most suitable combination of technologies and methods is applied providing a high degree of confidence in establishing reliable reserves estimates.

The all sources reserves replacement ratio achieved by Eni s subsidiaries and equity-accounted entities was 145% in 2015 (112% in 2014 and negative in 2013). Excluding the portfolio activities the organic reserves replacement ratio was 148% (112% in 2014 and 105% in 2013). The all sources reserves replacement ratio was calculated by dividing additions to proved reserves including sales and purchases of mineral-in-place by total production, each as derived from the tables of changes in proved reserves prepared in accordance with FASB Extractive Activities - Oil & Gas (Topic 932) (see the supplemental oil and gas information in "Item 18 Consolidated Financial Statements"). The reserves replacement ratio is a measure used by management to assess the extent to which produced reserves in the year are replaced by booked reserves total additions. Management considers the reserve replacement ratio to be an important indicator of the Company s ability to sustain its growth prospects. However, this ratio measures past performances and is not an indicator of future production because the ultimate recovery of reserves is subject to a number of risks and uncertainties. These include the risks associated with the successful completion of large-scale projects, including addressing ongoing regulatory issues and completion of infrastructures, reservoir performance, application of new technologies to improve the recovery factor as well as changes in oil&gas prices, political risks and geological and environmental risks. See "Item 3 Risks associated with the exploration and production of oil and natural gas Uncertainties in estimates of oil and natural gas reserves".

The average reserves life index of Eni s proved reserves was 10.7 years as of December 31, 2015 which included reserves of both subsidiaries and equity-accounted entities.

Eni s subsidiaries

Eni s subsidiaries added 849 mmBOE of proved oil&gas reserves in 2015. This comprised 636 mmBBL of liquids and 1,175 BCF of natural gas. Additions to proved reserves derived from: (i) revisions of previous estimates were 781 mmBOE mainly reported in Kazakhstan, Iraq, Egypt and Congo due to contractual revisions, continuous development activities and field performances; (ii) extensions and discoveries were 66 mmBOE, with major increases booked in Egypt and Indonesia following new discoveries and proved area extensions; (iii) improved recovery were 2 mmBOE mainly reported in Egypt; and (iv) sales of mineral-in-place related to the divestment of assets in Nigeria (16 mmBOE) and the United States (1 mmBOE).

Eni s share of equity-accounted entities

Additions in Eni s share of equity-accounted entities proved oil&gas amounted to 98 mmBOE in 2015 and derived from revisions of previous estimates reported in Venezuela and Angola.

Proved undeveloped reserves

Proved undeveloped reserves as of December 31, 2015 totaled 2,867 mmBOE. At year-end, proved undeveloped reserves of liquids amounted to 1,411 mmBBL, mainly concentrated in Africa and Kazakhstan. Proved undeveloped reserves of natural gas amounted to 7,994 BCF, mainly located in Africa and Americas. Proved undeveloped reserves of consolidated subsidiaries amounted to 1,272 mmBBL of liquids and 5,403 BCF of natural gas.

In 2015, total proved undeveloped reserves decreased by 302 mmBOE mainly due to: (i) reclassification to proved developed reserves (down by 550 mmBOE); and (ii) divestments (down by 5 mmBOE) in Nigeria. Partially offset by: (i) revisions of previous estimates (up by 204 mmBOE) mainly reported in Venezuela, Iraq and Egypt; (ii) extensions and discoveries (up by 48 mmBOE), in particular in Indonesia, Egypt and Ghana; and (iii) improved recovery (up 1 mmBOE) in particular in Egypt.

During 2015, Eni converted 550 mmBOE of proved undeveloped reserves to proved developed reserves due to the progress of development activities, production start-ups and project revisions. The main reclassifications to proved developed reserves related to the following fields/projects: Perla (Venezuela), Goliat and Midgard (Norway), Litchendjili (Congo) and M Pungi (Angola).

In 2015, capital expenditure amounted to approximately euro 9 billion and was made to progress the development of proved undeveloped reserves.

Reserves that remain proved undeveloped for five or more years are a result of several factors that affect the timing of the projects development and execution, such as the complex nature of the development project in adverse and remote locations, physical limitations of infrastructures or plant capacity and contractual limitations that establish production levels. The Company estimates that approximately 0.8 BBOE of proved undeveloped reserves have remained undeveloped for five years or more with respect to the balance sheet date, mainly related to: (i) the Kashagan project in Kazakhstan (approximately 0.5 BBOE), which will be progressively reclassified to proved developed reserves as a result of hooking-up new producing wells which are currently being completed and plant capacity expansion as a part of the sanctioned Phase 1 of the global development plan of the Kashagan field; (ii) certain Libyan gas fields (0.2 BBOE) where development completion and production start-ups are planned according to the delivery obligations set forth in a long-term gas supply agreement currently in force. In order to secure fulfillment of the contractual delivery quantities, Eni will implement phased production start-up from the relevant fields which are expected to be put in production over the next several years; and (iii) other minor projects where development activities are progressing. (See also our discussion under the "Risk Factors" section about risks associated with oil and gas development projects).

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

Delivery commitments

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

Eni is contractually committed under existing contracts or agreements to deliver in the next three years mainly natural gas to third parties for a total of approximately 479 mmBOE from producing assets located mainly in Algeria, Australia, Egypt, Libya, Nigeria, Norway and Venezuela.

The sales contracts contain a mix of fixed and variable pricing formulas that are generally referenced to the market price for crude oil, natural gas or other petroleum products. Management believes it can satisfy these contracts from quantities available from production of the Company s proved developed reserves and supplies from third parties based on existing contracts. Production will account for approximately 86% of delivery commitments.

Eni has met all contractual delivery commitments as of December 31, 2015.

Oil and gas production, production prices and production costs

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

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In 2015, oil and natural gas production available for sale averaged 1,688 KBOE/d (1,517 KBOE/d in 2014) increased by 11.3% from 2014. The increase was driven by new field start-ups and the continuing ramp-up of production at fields started in 2014, mainly reported in Angola, Venezuela, the United States and the United Kingdom, higher production in Libya and Iraq as well as the recovery of trade receivables for past investments in Iran (See "Disclosure pursuant to Section 13(r) of the Exchange Act"). These positive effects were partly offset by the decline of mature fields. New field start-ups and ramp-ups of production added an estimated 139 KBOE/d of new production.

Liquids production (908 KBBL/d) increased by 80 KBBL/d, or 9.7%, due to higher production in Libya, Iran and Iraq as well as new fields start-ups and ramp-ups in particular in Angola, the United States and Norway.

Natural gas production (4,284 mmCF/d) reported an increase of 502 mmCF/d, or 13.3% from 2014. The start-ups in Venezuela, the United Kingdom, Egypt and the United States, as well as higher production in Libya more than offset the decline of mature fields.

Oil and gas production sold amounted to 614.1 mmBOE. The 1.9 mmBOE difference over production on an available-for-sale basis (616 mmBOE) reflected mainly changes in inventories and other factors. Approximately 61% of liquids production sold (330.1 mmBBL) was destined to Eni s mid-downstream sectors. About 25% of natural gas production sold (1,560 BCF) was destined to Eni s Gas & Power segment.

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

2013 Production available for sale [(a)]		**Italy**	**Rest of Europe**	**North Africa**	**Sub-Saharan Africa**	**Kazakhstan**	**Rest of Asia**	**Americas**	**Australia and Oceania**	**Total**
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	179	149	523	305	96	101	104	29	**1,486**
	(mmBOE)	65	54	191	111	35	36	38	11	**541**
Eni share of equity-accounted entities	(KBOE/d)			5	2		34	10		**51**
	(mmBOE)			2	1		13	4		**20**
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	71	77	248	242	61	43	61	10	**813**
	(mmBBL)	26	28	91	88	22	16	22	4	**297**
Eni share of equity-accounted entities	(KBBL/d)			4			6	10		**20**
	(mmBBL)			1			2	4		**7**
Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	593	395	1,510	349	195	322	234	105	**3,703**
	(BCF)	217	144	551	127	71	118	85	38	**1,351**
Eni share of equity-accounted entities	(mmCF/d)			4	7		154			**165**
	(BCF)			2	3		56			**61**

(a) It excludes production volumes of natural gas consumed in operations. Said volumes were 451 mmCF/d, or 30 mmBOE.

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2014 Production available for sale [(a)]		Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
Hydrocarbons production										
Eni consolidated subsidiaries	(KBOE/d)	171	184	528	305	85	87	112	25	**1,497**
	(mmBOE)	63	67	193	111	31	31	41	9	**546**
Eni share of equity-accounted entities	(KBOE/d)			4	2		4	10		**20**
	(mmBOE)			1	1		2	4		**8**
Liquids production										
Eni consolidated subsidiaries	(KBBL/d)	73	93	249	230	52	36	74	6	**813**
	(mmBBL)	27	34	91	84	19	13	27	2	**297**
Eni share of equity-accounted entities	(KBBL/d)			4			1	10		**15**
	(mmBBL)			1				4		**5**
Natural gas production										
Eni consolidated subsidiaries	(mmCF/d)	541	498	1,533	411	181	279	205	106	**3,754**
	(BCF)	198	182	559	150	66	102	75	39	**1,371**
Eni share of equity-accounted entities	(mmCF/d)			3	7		18			**28**
	(BCF)			1	3		6			**10**

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

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

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

Volumes of oil and natural gas purchased under long-term supply contracts with foreign governments or similar entities in properties where Eni acts as producer totaled 84 KBOE/d, 78 KBOE/d and 67 KBOE/d in 2015, 2014 and 2013, respectively.

The tables below provide Eni subsidiaries and its equity-accounted entities average sales prices per unit of liquids and natural gas by geographical area for each of the last three fiscal years. Also Eni subsidiaries and its equity-accounted entities average production cost per unit of production are provided. The average production cost does not include any ad valorem or severance taxes.

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AVERAGE SALES PRICES AND PRODUCTION COST PER UNIT OF PRODUCTION

($)	Italy	Rest of Europe	North Africa	Sub-Saharan Africa	Kazakhstan	Rest of Asia	Americas	Australia and Oceania	Total
2013									
Consolidated subsidiaries									
Oil and condensates, per BBL	98.50	98.97	100.42	105.13	99.37	99.69	85.27	98.72	**100.20**
Natural gas, per KCF	11.65	10.62	7.96	2.16	0.64	5.83	3.37	7.80	**7.41**
Average production cost, per BOE	14.58	17.49	6.72	19.60	7.23	9.32	12.08	18.17	**12.19**
Equity-accounted entities									
Oil and condensates, per BBL			17.96			33.87	93.32		**64.92**
Natural gas, per KCF			6.29			3.49			**4.00**
Average production cost, per BOE			11.87			3.48	50.57		**16.68**
2014									
Consolidated subsidiaries									
Oil and condensates, per BBL	87.80	88.80	88.99	93.45	91.86	77.99	79.13	91.61	**88.90**
Natural gas, per KCF	8.74	8.49	8.08	2.12	0.62	6.18	3.96	7.46	**6.83**
Average production cost, per BOE	15.19	13.61	6.79	18.88	8.94	10.70	11.75	20.14	**12.00**
Equity-accounted entities									
Oil and condensates, per BBL			17.94			65.90	81.48		**70.56**
Natural gas, per KCF			6.08			15.64			**14.13**
Average production cost, per BOE			12.50			9.79	42.27		**26.18**
2015									
Consolidated subsidiaries									
Oil and condensates, per BBL	43.46	45.88	46.66	49.91	48.26	40.10	43.36	45.84	**46.46**
Natural gas, per KCF	6.92	6.30	4.69	1.49	0.47	4.83	2.20	5.07	**4.54**
Average production cost, per BOE	11.08	10.93	5.72	14.08	7.93	6.48	11.61	14.49	**9.18**
Equity-accounted entities									
Oil and condensates, per BBL			18.03			27.89	38.18		**35.15**
Natural gas, per KCF			3.78			9.27	4.24		**5.30**
Average production cost, per BOE			8.98			8.67	16.48		**14.51**

Development activities

In 2015, a total of 335 development wells were drilled (132.4 of which represented Eni s share) as compared to 440 development wells drilled in 2014 (191 of which represented Eni s share) and 463 development wells drilled in 2013 (187.2 of which represented Eni s share). The drilling of 103 development wells (35 of which represented Eni s share) is currently underway.

The table below summarizes the number of the Company s net interest in productive and dry development wells completed in each of the past three years and the status of the Company s development wells in the process of being drilled as of December 31, 2015. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

DEVELOPMENT WELL ACTIVITY

Net wells completed

	2013		2014		2015		Wells in progress at Dec. 31, 2015	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
Italy	7.4	1.0	12.5		6.0		6.0	3.6
Rest of Europe	6.3		9.8	1.0	10.2	0.1	14.0	3.0
North Africa	61.6	3.3	54.5	1.0	30.5	2.8	17.0	9.2
Sub-Saharan Africa	26.3	1.2	31.6		22.0	2.5	28.0	4.8
Kazakhstan	0.3		1.5		4.7		16.0	3.1
Rest of Asia	61.7	4.3	54.2	1.6	29.7	5.9	6.0	2.3
Americas	13.8		22.1	0.7	17.4	0.1	16.0	9.0
Australia and Oceania			0.1	0.4	0.5			
Total including equity-accounted entities	**177.4**	**9.8**	**186.3**	**4.7**	**121.0**	**11.4**	**103.0**	**35.0**

Exploration activities

In 2015, a total of 29 new exploratory wells were drilled (19.1 of which represented Eni s share), as compared to 44 exploratory wells drilled in 2014 (25.8 of which represented Eni s share) and 53 exploratory wells drilled in 2013 (27.8 of which represented Eni s share).

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The overall commercial success rate was 16.7% (25.1% net to Eni) as compared to 31.3% (38.0% net to Eni) and 36.9% (38.5% net to Eni) in 2014 and 2013, respectively.

The following table summarizes the Company s net interests in productive and dry exploratory wells completed in each of the last three fiscal years and the number of exploratory wells in the process of being drilled and evaluated as of December 31, 2015. A dry well is one found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

EXPLORATORY WELL ACTIVITY

	Net wells completed						Wells in progress at Dec. 31, (1)	
	2013		2014		2015		2015	
(units)	Productive	Dry	Productive	Dry	Productive	Dry	Gross	Net
taly				0.6			4.0	2.8
Rest of Europe		3.4		4.3		2.2	9.0	2.3
North Africa	4.9	5.4	3.5	4.3	3.3	5.8	15.0	12.5
Sub-Saharan Africa	3.2	6.6	7.3	7.3	0.6	2.9	34.0	17.8
Kazakhstan		0.4					6.0	1.1
Rest of Asia	4.3	2.7	1.3	4.3		3.4	7.0	2.3
Americas	0.2	1.2	2.0	1.4	1.0	0.3	4.0	2.5
Australia and Oceania		0.5		0.9			1.0	0.3
Total including equity-accounted entities	**12.6**	**20.2**	**14.1**	**23.1**	**4.9**	**14.6**	**80.0**	**41.6**

(1) Includes temporary suspended wells pending further evaluation.

Oil and gas properties, operations and acreage

In 2015, Eni performed its operations in 42 countries located in five continents. As of December 31, 2015, Eni s mineral right portfolio consisted of 852 exclusive or shared rights of exploration and development activities for a total acreage of 342,708 square kilometers net to Eni of which developed acreage of 40,640 square kilometers and undeveloped acreage of 302,068 square kilometers net to Eni. In 2015, changes in total net acreage mainly derived from: (i) new leases mainly in Egypt, Mexico, Myanmar, the United Kingdom and Ivory Coast for a total acreage of approximately 21,500 square kilometers; (ii) the total relinquishment of licenses mainly in Congo, Ghana, Italy, Nigeria, Norway, Pakistan, Tunisia and the United States, covering an acreage of approximately 15,600 square kilometers; and (iii) interest increase in Australia and partial relinquishment in Indonesia for a total net acreage of 2,000 square kilometers.

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The table below provides certain information about the Company s oil&gas properties. It provides the total gross and net developed and undeveloped oil and natural gas acreage in which the Group and its equity-accounted entities had interest as of December 31, 2015. A gross acreage is one in which Eni owns a working interest.

	December 31, 2014	December 31, 2015							
	Total net acreage (a)	Number of interests	Gross developed acreage (a) (b)	Gross undeveloped acreage (a)	Total gross acreage (a)	Net developed acreage (a) (b)	Net undeveloped acreage (a)	Total net acreage (a)
EUROPE	**44,842**	**274**	**15,873**	**52,732**	**68,605**	**10,989**	**34,134**	**45,123**
Italy	**17,297**	**147**	**10,647**	**10,436**	**21,083**	**8,924**	**8,051**	**16,975**
Rest of Europe	**27,545**	**127**	**5,226**	**42,296**	**47,522**	**2,065**	**26,083**	**28,148**
Cyprus	10,018	3		12,523	12,523		10,018	10,018
Croatia	987	2	1,975		1,975	987		987
Greenland	1,909	2		4,890	4,890		1,909	1,909
Norway	3,672	56	2,310	7,594	9,904	452	2,662	3,114
Portugal	6,370	3		9,099	9,099		6,370	6,370
United Kingdom	744	48	941	1,501	2,442	626	1,279	1,905
Other countries	3,845	13		6,689	6,689		3,845	3,845
AFRICA	**159,341**	**283**	**63,142**	**260,577**	**323,719**	**19,788**	**137,653**	**157,441**
North Africa	**21,693**	**119**	**30,392**	**26,704**	**57,096**	**13,778**	**11,921**	**25,699**
Algeria	1,179	42	3,222	187	3,409	1,148	31	1,179
Egypt	4,946	57	5,623	17,829	23,452	2,121	7,547	9,668
Libya	13,294	10	17,947	8,688	26,635	8,951	4,343	13,294
Tunisia	2,274	10	3,600		3,600	1,558		1,558
Sub-Saharan Africa	**137,648**	**164**	**32,750**	**233,873**	**266,623**	**6,010**	**125,732**	**131,742**
Angola	4,327	72	7,688	13,608	21,296	987	3,417	4,404
Congo	2,883	26	1,794	943	2,737	971	383	1,354
Gabon	7,615	6		7,615	7,615		7,615	7,615
Ghana	1,664	2		226	226		100	100
Ivory Coast		1		1,431	1,431		429	429
Kenya	40,426	7		61,363	61,363		40,426	40,426
Liberia	1,841	3		7,364	7,364		1,841	1,841
Mozambique	5,103	6		3,911	3,911		1,956	1,956
Nigeria	7,638	36	23,268	8,747	32,015	4,052	3,380	7,432
South Africa	32,847	1		82,202	82,202		32,881	32,881
Other countries	33,304	4		46,463	46,463		33,304	33,304
ASIA	**109,237**	**70**	**17,556**	**202,632**	**220,188**	**5,803**	**111,380**	**117,183**
Kazakhstan	**869**	**6**	**2,391**	**2,542**	**4,933**	**442**	**427**	**869**
Rest of Asia	**108,368**	**64**	**15,165**	**200,090**	**215,255**	**5,361**	**110,953**	**116,314**
China	7,075	8	77	7,056	7,133	13	7,056	7,069
India	6,167	11	206	16,546	16,752	109	6,058	6,167
Indonesia	26,248	14	3,218	31,415	34,633	1,217	23,907	25,124
Iraq	446	1	1,074		1,074	446		446
Myanmar	7,065	4		24,080	24,080		20,050	20,050
Pakistan	9,467	15	10,390	11,486	21,876	3,396	5,414	8,810
Russia	20,862	3		62,592	62,592		20,862	20,862
Timor Leste	1,230	1		1,538	1,538		1,230	1,230

Turkmenistan	180	1	200		200	180		180
Vietnam	26,384	5		30,777	30,777		23,132	23,132
Other countries	3,244	1		14,600	14,600		3,244	3,244
AMERICAS	**7,943**	**211**	**5,245**	**9,458**	**14,703**	**3,351**	**3,277**	**6,628**
Ecuador	1,985	1	1,985		1,985	1,985		1,985
Mexico		3		67	67		67	67
Trinidad & Tobago	66	1	382		382	66		66
United States	3,500	192	1,617	2,301	3,918	803	1,315	2,118
Venezuela	1,066	6	1,261	1,543	2,804	497	569	1,066
Other countries	1,326	8		5,547	5,547		1,326	1,326
AUSTRALIA AND OCEANIA	**13,376**	**14**	**1,140**	**21,679**	**22,819**	**709**	**15,624**	**16,333**
Australia	13,376	14	1,140	21,679	22,819	709	15,624	16,333
Total	**334,739**	**852**	**102,956**	**547,078**	**650,034**	**40,640**	**302,068**	**342,708**

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

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The table below provides the number of gross and net productive oil and natural gas wells in which the Group companies and its equity-accounted entities had an interest as of December 31, 2015. A gross well is a well in which Eni owns a working interest. The number of gross wells is the total number of wells in which Eni owns a whole or fractional working interest. The number of net wells is the sum of the whole or fractional working interests in a gross well. One or more completions in the same bore hole are counted as one well. Productive wells are producing wells and wells capable of production. The total number of oil and natural gas productive wells is 9,241 (3,667.5 of which represent Eni s share).

Productive oil&gas wells at Dec. 31, 2015 [(a)]

	Oil wells		Natural gas wells	
(units)	Gross	Net	Gross	Net
Italy	238.0	192.1	605.0	523.6
Rest of Europe	363.0	59.7	179.0	100.6
North Africa	1,782.0	941.1	211.0	90.7
Sub-Saharan Africa	3,065.0	613.4	344.0	27.2
Kazakhstan	185.0	50.7		
Rest of Asia	688.0	457.2	998.0	380.9
Americas	230.0	121.1	328.0	101.6
Australia and Oceania	7.0	3.8	18.0	3.8
Total including equity-accounted entities	**6,558.0**	**2,439.1**	**2,683.0**	**1,228.4**

(a) Multiple completion wells included above: approximately 2,234 (799.1 net to Eni).

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

Italy

Eni has been operating in Italy since 1926. In 2015, Eni s oil&gas production amounted to 161 KBOE/d. Eni s activities in Italy are deployed in the Adriatic and Ionian Sea, the Central Southern Apennines, mainland and offshore Sicily and the Po Valley. Eni s exploration and development activities in Italy are regulated by concession contracts (51 operated onshore and 64 operated offshore) and exploration licenses (11 onshore and 9 offshore).

The Adriatic and Ionian Sea represents Eni s main production area, accounting for 47% of Eni s domestic production in 2015. Main operated fields are Barbara, Cervia/Arianna, Annamaria, Luna, Angela-Angelina, Hera Lacinia, Bonaccia and Porto Garibaldi.

Eni is the operator of the Val d Agri concession (Eni s interest 60.77%) in the Basilicata Region in Southern Italy. Production from the Monte Alpi, Monte Enoc and Cerro Falcone fields is treated by the Viggiano oil center. On March 31, 2016, as part of an investigation commenced by the Italian Public Prosecutor of Potenza for alleged environmental crimes that is disclosed in the legal proceeding section in the notes to the financial statements (see page F-86), it was ordered the seizure of certain plants that are functional to the activity of hydrocarbons production, which has been shut down. The interruption is currently affecting a production of approximately 60 KBOE/d net to Eni. The value-in-use of the Val d Agri CGU determined as part of the impairment review of 2015 significantly exceeds the CGU carrying amount, so to exclude that even under the worst-case production shutdown among the currently foreseeable scenarios a reduction of the CGU book value at the reporting date might occur.

In Sicily, Eni operates 12 production concessions onshore and 3 offshore. The main fields are Gela, Ragusa, Tresauro, Giaurone, Fiumetto and Prezioso, which in 2015 accounted for approximately 11% of Eni s production in Italy.

Development activities included: (i) a new gas treatment unit realized at the Val d Agri concession;
(ii) maintenance and optimization of production, mainly at the Barbara, Anemone, Annalisa, Armida and Guendalina fields; and (iii) start-up of the Bonaccia NW project and ongoing development activities at the Clara field.

In the medium-term, management expects to achieve stable production level driven by continuing ramp-up at the Val d Agri fields, new field projects and production optimization activities offsetting mature fields decline.

Rest of Europe

Eni s operations in the Rest of Europe are conducted mainly in Croatia, Norway and the United Kingdom. In

2015, the Rest of Europe accounted for 11% of Eni s total worldwide production of oil and natural gas.

Croatia. Eni has been present in Croatia since 1996. In 2015, Eni s production of natural gas averaged approximately 19 mmCF/d. Activities are deployed in the Adriatic Sea near the city of Pula.

Exploration and production activities in Croatia are regulated by PSAs.

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

Norway. Eni has been operating in Norway since 1965. Eni s activities are performed in the Norwegian

Sea, in the Norwegian section of the North Sea and in the Barents Sea. Eni s production in Norway amounted to 103 KBOE/d in 2015.

Exploration and production activities in Norway are regulated by Production Licenses (PL). According to a PL, the holder is entitled to perform seismic surveys and drilling and production activities for a given number of years with possible extensions.

Eni currently holds interests in 10 production areas in the Norwegian Sea. The principal producing fields are Åsgard (Eni s interest 14.82%), Kristin (Eni s interest 8.25%), Heidrun (Eni s interest 5.17%), Mikkel (Eni s interest 14.9%), Tyrihans (Eni s interest 6.2%), Marulk (Eni operator with a 20% interest) and Morvin (Eni s interest 30%) which in 2015 accounted for 74% of Eni s production in Norway.

Eni holds interests in 2 production licenses in the Norwegian section of the North Sea. The main producing field is Ekofisk (Eni s interest 12.39%) in PL 018, which in 2015 produced approximately 24 KBOE/d net to Eni and accounted for 23% of Eni s production in Norway. The license expires in 2028, and negotiations are ongoing to grant an extension.

Eni is currently performing development activities in the Barents Sea. In 2015, operations have been focused on developing the Goliat discovery made in 2000 at a water depth of 370 meters in PL 229 (Eni operator with a 65% interest). The license expires in 2042. In March 2016, production start-up was achieved at the Goliat field. Production plateau is estimated at 65 KBBL/d net to Eni. The project includes a subsea system consisting of 22 wells, of which 12 are oil producers, 7 water injectors and 3 gas injectors, linked to the cylindrical FPSO by subsea production and injection flowlines.

At the beginning of 2015, production start-up was achieved at the Eldfisk 2 field (Eni s interest 12.39%) in the North Sea and in September 2015, Åsgard Subsea Compression project started up in order to optimize production from Mitgard (Eni s interest 14.8%) and Mikkel fields (Eni s interest 14.9%) in the Norwegian Sea.

Other activities concerned the maintenance and optimization of the production at the Ekofisk field (Eni s interest 12.39%) and start-up of the FSU at Heidrun field (Eni s interest 5.2%) in the Norwegian Sea.

In 2015, Eni was awarded two exploration licenses: (i) the operatorship and a 40% interest in the PL 806 license in the Barents Sea; and (ii) a 13.12% interest in the PL 044C license in the North Sea. Focus of the exploration activity in 2015 were the preparatory activities for an exploration drilling campaign planned for 2016.

United Kingdom. Eni has been present in the United Kingdom since 1964. Eni s activities are carried out in the British section of the North Sea and the Irish Sea. In 2015, Eni s net production of oil&gas averaged 72

KBOE/d. Exploration and production activities in the United Kingdom are regulated by concession contracts.

Eni currently holds interests in 5 production areas of which the Liverpool Bay is operated by Eni with a 100% interest and Hewett Area is operated with an 89.3% interest. The other fields are Elgin/Franklin (Eni s interest 21.87%), J Block and Jasmine (Eni s interest 33%), Jade (Eni s interest 7%) and MacCulloch (Eni s interest 40%), which in 2015 accounted for 59% of Eni s production in the United Kingdom.
Eni started production of the Phase 2 at the West Franklin field (Eni s interest 21.87%), following the completion of two productive wells.

Development activities concerned drilling activities for the completion of the development of Jasmine field (Eni s interest 33%).

In 2015, Eni was awarded four exploration licenses in the Central North Sea, with interests ranging from 9.13% to 100%. In addition, Eni finalized the acquisition of three licenses in the Southern North Sea, with a 100% interest.

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North Africa

Eni s operations in North Africa are conducted in Algeria, Egypt, Libya and Tunisia. In 2015, North Africa accounted for 38% of Eni s total worldwide production of oil and natural gas.

Algeria. Eni has been present in Algeria since 1981. In 2015, Eni s oil&gas production averaged 89 KBOE/d.

Operated activities are located in the Bir Rebaa desert, in the Central-Eastern area of the country: (i) blocks 403a/d (Eni s interest from 65% to 100%); (ii) block Rom North (Eni s interest 35%); (iii) blocks 401a/402a (Eni s interest 55%); (iv) blocks 403 (Eni s interest 50%); (v) block 405b (Eni s interest 75%); and (vi) block 212 (Eni s interest 22.38%) with discoveries already made. In addition, Eni holds interest in the non-operated block 404 and block 208 with a 12.25% stake.

Exploration and production activities in Algeria are regulated by Production Sharing Agreements (PSAs) and concession contracts.

Production in blocks 403a/d and Rom North comes mainly from the HBN and Rom and satellites fields and represented approximately 21% of Eni s production in Algeria in 2015. In 2015, Eni signed with relevant authorities a five-year extension for the operated field Rom East (Eni s interest 100%).
Production in blocks 401a/402a comes mainly from the ROD/SFNE and satellite fields and accounted for approximately 14% of Eni s production in Algeria in 2015.

The main fields in block 403 are BRN, BRW and BRSW, which accounted for approximately 10% of Eni s production in Algeria in 2015.

The main fields in block 404 are HBN and HBNS and satellites, which accounted for approximately 21% of Eni s production in Algeria in 2015.

Production in block 405b comes mainly from MLE-CAFC project and accounted for approximately 16% of Eni s production in the country. In 2015, development and optimization activities progressed at the MLE-CAFC production fields, by means of construction and infilling activities, as well as production optimization. The project includes an additional oil phase with a start-up expected in 2017, targeting a production plateau more than 30 KBOE/d net to Eni.

The El-Merk field is the main production project in the block 208 and accounted for approximately 18% of Eni s production in Algeria in 2015.

Activities during the year concerned infilling wells and production optimization in all operated and participated blocks in the Country.

Egypt. Eni has been present in Egypt since 1954. In 2015, Eni s share of production in this country amounted to 177 KBOE/d and accounted for 10% of Eni s total annual hydrocarbon production. Eni s main producing liquid fields are located in the Gulf of Suez, primarily the Belayim field (Eni s interest 100%), and in the Western Desert mainly the Melehia (Eni s interest 76%) and the Ras Qattara (Eni s interest 75%) concessions. Gas production mainly comes from the operated or participated concession of North Port

Said (Eni s interest 100%), El Temsah (Eni s interest 50%), Baltim (Eni s interest 50%) and Ras el Barr (Eni s interest 50%, non operated), located offshore the Nile Delta. In 2015, production from these large concessions accounted for approximately 92% of Eni s production in Egypt.

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

In March 2015, Eni and the Egyptian Ministry of Petroleum and Mineral Resources signed a framework agreement, which comprises a plan to invest up to $5 billion (at 100%) in the development of the Country s oil&gas reserves over the next few years. The agreement also includes a revision of certain Eni s ongoing oil contracts, with the economic effects retroactive to January 1, 2015. The agreement also comprises the identification of new measures to reduce overdue amounts of trade receivables relating to hydrocarbons supplies to Egyptian State-owned companies. In November 2015, as foreseen by the agreements, Eni signed three amendments for the concessions of Sinai 12 (Eni s interest 100%) and Abu Madi, North Port Said (Eni s interest 100%) and Baltim (Eni operator with a 50% interest), for the realization of projects to be implemented in the next years. In addition, Eni signed a new Concession Agreement for the Ashrafi area (Eni s interest 25%). Certain planned activities are currently in the execution phase and one additional well in Baltim concession has already been put into production.

In 2015, Concession Agreements were ratified for the following blocks: (i) the Southwest Melehia (Eni s interest 100%) in the Western Desert; (ii) Karawan (Eni operator with a 50% interest) and North Leil (Eni s interest 100%) in the deep offshore of Mediterranean Sea; and (iii) North El Hammad (Eni operator with 37.5% interest) and North Ras El Esh (Eni s interest 50%) in the offshore Nile Delta, which is still expected to be ratified by the Country s Authorities.

Exploration activities yielded positive results with the following discoveries: (i) the large Zohr gas discovery, in the operated Shorouk license (Eni s interest 100%) located in the deep offshore of Mediterranean Sea. Based on ongoing studies management believes that this discovery contains a large amount of gas resources. In February 2016, the Egyptian Ministry of Petroleum and Mineral Resources has approved to award to Eni the Zohr Development Lease that allows the start-up of the development program at the Zohr gas field. The first gas is expected at the end of 2017. In addition, appraisal activity yielded positive results with the Zohr 2X well, the first delineation well. The delineation campaign provides the drilling of three additional wells; (ii) oil&gas discovery with the Melehia West Deep well in the Melehia concession (Eni s interest 76%) located in the Western Desert; (iii) the Sidri-18 oil discovery in the Abu Rudeis concession (Eni s interest 100%) in the Gulf of Suez; and (iv) an important gas discovery in the Nooros exploration prospect, located in the Abu Madi West license (Eni s interest 75%) in the Nile Delta. The discovery was put into production in two months time through a tie-in to the existing Abu Madi gas treatment plant. In February 2016, new success exploration was achieved with the drilling of the Nidoco North 1X well. Production start-up is expected in the second quarter 2016 and will allow to achieve an overall production of 45 KBOE/d in the area.

Production activities during the year concerned mainly infilling wells in the Gulf of Suez and Western Desert areas and for gas in El Temsah and Baltim and other production optimization activities aimed to optimize reserve recovery.

Libya. Eni started operations in Libya in 1959.

In recent years, Eni s production levels in Libya were negatively impacted by an internal revolution and a change of regime in 2011, which led to a prolonged period of political and social instability characterized by acts of local conflict, social unrest, protests, strikes and other similar events. Those political development forced Eni to temporarily interrupt or reduce its producing activities, negatively affecting Eni s results of operations and cash flow until the situation began to stabilize. Eni expects that those risks will continue to affect Eni s operations in the country. Particularly, the uncertain socio-political outlook in Libya was factored in the Company s projections of future production levels. In 2015, Eni s facilities in Libya produced on average 358 KBOE/d, registering an increase of approximately 54% compared to 2014. For further information on this matter, see "Item 3 Risk factors".

Production activity is carried out in the Mediterranean Sea near Tripoli and in the Libyan Desert area and includes six contract areas. Onshore contract areas are: (i) Area A consisting in the former concession 82 (Eni s interest 50%); (ii) Area B, former concessions 100 (Bu Attifel

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field) and the NC 125 Block (Eni s interest 50%); (iii) Area E with El Feel (Elephant) field (Eni s interest 33.3%); and (iv) Area F with Block 118 (Eni s interest 50%). Offshore contract areas are: (i) Area C with the Bouri oil field (Eni s interest 50%); and (ii) Area D with Blocks NC 41 and NC 169 (onshore) that feed the Western Libyan Gas Project (Eni s interest 50%).

In the exploration phase, Eni is operator of four onshore blocks in the Kufra area (186/1, 2, 3 & 4) and in the onshore contract Areas A, B and offshore Area D.

Exploration and production activities in Libya are regulated by six Exploration and Production Sharing Agreement contracts (EPSA). The licenses of Eni s assets in Libya expire in 2042 and 2047 for oil&gas properties, respectively.

In January 2015, Eni and the State company NOC signed an agreement that ensures during the 2015-2018 four-year period the sale of the associated gas to the production of the Bu Attifel oilfield in the contractual area B.

Development activities in the contractual area D concerned: (i) the linkage and the start-up of three infilling wells, in addition to the activity of production optimization at the Wafa field; and (ii) the start-up of the second development phase of the Bahr Essalam field by means of the start-up of drilling campaign and the award of EPC contract for the construction of linkage subsea facility to the onshore treatment plans.

Exploration activities near-field yielded positive results in the contractual area D, with gas and condensates discoveries: (i) in the offshore Bahr Essalam South exploration prospect, nearby to the Bahr Essalam production field; and (ii) in the offshore Bouri North exploration prospect, nearby to the Bouri production field.

Morocco. In March 2016, Eni signed a Farm-Out Agreement (FOA) with Chariot Oil & Gas that includes the operatorship to Eni and a 40% stake enter into Rabat Deep Offshore exploration permits I-VI offshore Morocco. The completion of this FOA is subject to the authorization of the Moroccan Authorities, to current partners approval and other conditions precedent.

Tunisia. Eni has been present in Tunisia since 1961. In 2015, Eni s production amounted to 11 KBOE/d.

Eni s activities are located mainly in the Southern Desert areas and in the Mediterranean offshore facing Hammamet.

Exploration and production in this country are regulated by concessions.

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

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

Sub-Saharan Africa

Eni s operations in Sub-Saharan Africa are conducted mainly in Angola, Congo, Ghana, Mozambique and Nigeria. In 2015, Sub-Saharan Africa accounted for 19% of Eni s total worldwide production of oil and natural gas.

Angola. Eni has been present in Angola since 1980. In 2015, Eni s production averaged 95 KBOE/d. Eni s activities are concentrated in the conventional and deep offshore.

The main Eni s asset in Angola is the Block 15/06 (Eni operator with a 36.84% interest) with the West Hub project, where production started up in 2014 and the East Hub development project is underway with start-up expected in 2017. Eni participates in other producing blocks: (i) Block 0 in Cabinda (Eni s interest 9.8%) north

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of the Angolan coast; (ii) Development Areas in the former Block 3 (Eni s interest 12%) offshore the Congo Basin; (iii) Development Areas in the Block 14 (Eni s interest 20%) in the deep offshore west of Block 0; (iv) the Lianzi Development Area in the Block 14K/A IMI (Eni s interest 10%), where a unitization was implemented with the Congo-Brazaville area; and (v) Development Areas in the former Block 15 (Eni s interest 20%) in the deep offshore of the Congo Basin.

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

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

In 2015, Eni and the State company Sonangol signed certain agreements aimed at strengthening strategic and operational partnership, which include: (i) the commitment to upgrade the current development plans for the Lobito refinery, owned by the Angolan national company, with Eni s expertise and know-how in the downstream sector including the potential synergies deriving from existing refineries; and (ii) the commitment to progress the ongoing evaluation of the gas resources in the Lower Congo Basin. In addition, Eni and Sonangol agreed a revision of certain contractual terms to support investments in the Block 15/06, where in January 2015, Eni obtained a three-year extension of the exploration period.

The development program of the West Hub project plans to hook up the Block s discoveries to the N Goma FPSO in order to support production plateau. In April 2015, production start-up was achieved at the Cinguvu field, following the first oil of the Sangos field, and in January 2016, Eni started production from the M Pungi field, with an overall production of approximately 25 KBBL/d net to Eni.

In addition, Eni started production at: (i) the Kizomba satellites Phase 2 project (Eni s interest 20%), in the deep offshore of the Country, by means of the start-up of further three fields connected to the existing FPSO. The peak production is estimated at approximately 80 KBBL/d; (ii) the Lianzi project (Eni s interest 10%), with the start-up of the first two wells which yielded approximately 25 KBBL/d by the end of the year. The start-up of an additional well in 2016 will allow to reach a production peak of approximately 35 KBBL/d; and (iii) the Gazela field (Eni s interest 12%), with a production of approximately 3 KBBL/d.

Other development activities concerned the Mafumeira project (Eni s interest 9.8%) with production start-up expected at the end of 2016.

In the medium term, management expects to increase Eni s production to above 140 KBOE/d reflecting additions from ongoing development projects.

Congo. Eni has been present in Congo since 1968. In 2015, production averaged 97 KBOE/d net to Eni. Eni s activities are concentrated in the conventional and deep offshore facing Pointe Noire and onshore.

Eni s main operated oil producing interests in Congo are the Zatchi (Eni s interest 56%), Loango (Eni s interest 42.5%), Ikalou (Eni s interest 100%), Djambala (Eni s interest 50%), Foukanda and Mwafi (Eni s interest 58%), Kitina (Eni s interest 52%), Awa Paloukou (Eni s interest 90%), M Boundi (Eni s interest 83%), Kouakouala (Eni s interest 75%), Nené Marine (Eni 65%), Zingali and Loufika (Eni s interest 100%) fields.

Other relevant not operated producing areas are a 35% interest in the Pointe Noire Grand Fond, PEX and Likouala permits.

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

Eni achieved production start-up of the Litchendjili field in the Marine XII block (Eni operator with a 65% interest) by means of the installation of a production platform, the construction of transport facilities and onshore treatment plant. Peak production is estimated at 14 KBOE/d net to Eni and is expected in 2016.

Development activities progressed at the Nené Marine production field started up in 2014, located in the Marine XII block, with the completion and start-up of the two additional productive wells. In 2015, the final investment decision for the Phase 2 of Nené Marine was sanctioned and start-up is expected in the second half of 2016.

Exploration activities yielded positive results in the Marine XII block with: (i) the Minsala N1 appraisal well, confirming the mineral potential of the Minsala discovery; and (ii) the Nkala Marine discovery.

In the medium term, management expects to maintain production on the present level.

Ghana. Eni has been present in Ghana since 2009 and currently is the operator of the Offshore Cape Three Points (Eni s interest 47.22%) permits which is regulated by a concession agreement. The license expires in 2036.

In 2015, Eni defined and signed a Gas Sale Agreement with the Ghana Authorities, as well as other agreements related to the guarantees for the sale of natural gas from the operated OCTP project, sanctioned and approved by the Ministry of Petroleum in December 2014. The integrated oil&gas development plan provides to put into production the Sankofa, Sankofa East and Gye Nyame discoveries. The first oil is expected in 2017 and the first gas in 2018. Peak production is estimated at 40 KBOE/d net to Eni in 2019.

In the year development activities concerned: (i) main contracts awarded for the realization of FPSO and offshore facilities; and (ii) the start-up of the development activities with the drilling of 5 development wells.

In March 2016, Eni was awarded the operatorship of the exploration license Cape Three Points Block 4 (Eni s interest 42.47%), located in the offshore of the country.

Mozambique. Eni has been present in Mozambique since 2006, following the acquisition of the Area 4 block (Eni operator with a 50% interest) located in the offshore Rovuma Basin. In 2011, Eni made the important gas discovery of Mamba. The Mamba reservoir extends through Area 4 and the adjacent Area 1 operated by Anadarko. In 2012, Eni made the Coral gas discovery which falls entirely in Area 4.

During the exploration period which has expired in 2015, six Discovery Areas (DA) have been identified. Multiple plans of development can be submitted in respect of each DA, which upon approval will give right to identify a Development and Production Area for a term of 30 years, further extendable.

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

In November 2015, according to a Decree Law approved in December 2014, which defines the Rovuma Basin fiscal regime and the terms for the onshore liquefaction projects, all the concessionaries of Area 4 and Area 1 signed the Utilization and Unit Operating Agreement (UUOA). The agreement concerns the development of the Mamba and Prosperidade natural gas straddling reservoirs. In addition, the two operators jointly submitted to the Authorities the request for the allocation of the areas designated to the construction of the onshore liquefaction facilities. The development plan of the first phase of the Mamba project includes construction of two onshore LNG trains with a combined capacity of 10 mmtonnes/y and the drilling of 16 subsea wells, with start-up in 2022. Eni expects to produce up to 12 TCF of gas according to its independent industrial plan, coordinated with the operator of Area 1. The FID is expected in 2017.

In February 2016, the local Authorities approved the first stage of the development plan of the Coral discovery. The project plans to put into production 5 TCF of gas and includes the construction of a floating unit for the treatment, liquefaction and storage of natural gas (Floating LNG - FLNG) with a capacity of 3.4 mmtonnes/y fed by 6 subsea wells. Start-up is expected in 2021. The EPCIC contracts award recommendation for the construction, installation and commissioning of the FLNG and supply of subsea equipment and drilling rig have been issued. Furthermore, the long-term LNG sale contract have been finalized. The FID is expected in 2016, after approval of all contracts and commercial agreements by Mozambique Authorities and JV partners.

In October 2015, Eni was awarded the operatorship of the exploration offshore Block A-5A (Eni s interest 34%). The block is located in the deep offshore of Zambesi covering an area of approximately 5,000 square kilometers.

Nigeria. Eni has been present in Nigeria since 1962. In 2015, Eni s oil&gas production averaged 132 KBOE/d located mainly onshore and offshore the Niger Delta.

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In the development/production phase Eni operates onshore Oil Mining Leases (OML) 60, 61, 62 and 63 (Eni s interest 20%) and offshore OML 125 (Eni s interest 85%) and OPL 245 (Eni s interest 50%), holding interests in OML 118 (Eni s interest 12.5%) and in OML 119 and 116 Service Contracts. As partners of SPDC JV, the largest joint venture in the country, Eni also holds a 5% interest in 19 onshore blocks and in 1 conventional offshore block and with a 12.86% in 2 conventional offshore blocks.

In the exploration phase Eni operates offshore OML 134 (Eni s interest 85%), OPL 2009 (Eni s interest 49%); and onshore OPL 282 (Eni s interest 90%) and OPL 135 (Eni s interest 48%). Eni also holds a 12.5% interest in OML 135.

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

Eni completed activities and achieved production start-ups at: (i) the Bonga NW project, by means of the linkage of additional productive and infilling wells to the existing FPSO; and (ii) the Abo project Phase 3, by means of the linkage of two additional production wells to the existing production facilities in the area.

Development activities concerned: (i) the OML 28 block (Eni s interest 5%), where the drilling campaign progressed within the integrated project in the Gbara-Ubie area, aimed to supply natural gas to the Bonny liquefaction plant with start-up expected in 2016; and (ii) the OML 43 block (Eni s interest 5%), where the development plan of the Forkados-Yokri field provides the drilling of 24 producing wells, the upgrading of existing flowstations and the construction of transport facilities. Start-up is expected in 2016.

Eni holds a 10.4% interest in the Nigeria LNG Ltd joint venture, which runs the Bonny liquefaction plant located in the Eastern Niger Delta. The plant is operational, with a treatment capacity of approximately 1,236 BCF/y of feed gas corresponding to a production of 22 mmtonnes/y of LNG on six trains. The seventh unit is being engineered as it is in the planning phase. When fully operational, total capacity will amount to approximately 30 mmtonnes/y of LNG, corresponding to a feedstock of approximately 1,624 BCF/y. Natural gas supplies to the plant are currently provided under gas supply agreements with an expiring date in eighteen years from the SPDC JV and the NAOC JV, the latter operating the OMLs 60, 61, 62 and 63 blocks with an average amount of approximately 2,825 mmCF/d for the next four years (approximately 268 mmCF/d net to Eni corresponding to approximately 48 KBOE/d). LNG production is sold under long-term contracts and exported to the United States, Asian and European markets by the Bonny Gas Transport fleet, wholly owned by Nigeria LNG Co. During 2015, six new vessels were launched.

In the medium term, management expects to increase Eni s production in Nigeria to approximately 140 KBOE/d.

Kazakhstan

Eni has been present in Kazakhstan since 1992. Eni is co-operator of the Karachaganak field and partner in the North Caspian Sea Production Sharing Agreement (NCSPSA). In 2015, Eni s operations in Kazakhstan accounted for 5% of its total worldwide production of oil and natural gas.

In June 2015, Eni and KazMunayGas (KMG) signed an agreement on the transfer to Eni of the 50% stake for exploration and production activities in the Isatay block located in the Kazakh sector of the Caspian Sea. The transfer is expected to be finalized after all necessary approvals required by law. The Isatay block is estimated to have significant potential oil resources and will be operated by a joint operating company established by KMG and Eni on a 50/50 basis. In addition, after the finalization of the FEED, the activities related to the contracts award for the construction of a shipyard in Kuryk started, as provided by the agreements signed in 2014.

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

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

On June 13, 2015, the Consortium completed the process of setting up a new operating model which had started in October 2014, when Eni transferred its 100% interest in Agip Kazakhstan North Caspian Operating Co NV (AKCO) to the operator North Caspian Operating Co BV (NCOC BV), and AKCO was redenominated North Caspian Operating Co NV (NCOC NV). Subsequent merge transactions with NCOC BV and other agents of NCOC BV were completed in June 2015 resulting in the current operating model which provides that the company NCOC NV, participated by the seven partners of the Consortium, acts as the sole operator of all exploration, development and production activities at the Kashagan field. The objective of the restructuring is to execute the development of the project targeting streamlined decision-making process, increased efficiency in operations and lower costs.

In December 2015, the Authority of the Republic of Kazakhstan approved the Amendment 5 to the development plan and budget for the Phase 1 of the Kashagan project (the so-called "Experimental Program") which defines the update to the project schedule and budget and the activities for the replacement of the damaged pipelines, which forced the Consortium to shut down the production at the Kashagan field soon after the start-up in September 2013.

During the year activities progressed to replace the damaged pipelines and the Consortium expects to complete the installation works in the second half of 2016 with production re-start by the end of 2016. The production capacity of 370 KBBL/d planned for the Phase 1 is expected to be achieved during 2017.

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

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

As of December 31, 2015, Eni s proved reserves booked for the Kashagan field amounted to 611 mmBOE, recording an increase of 31 mmBBL compared to 2014 mainly due to lower marker Brent price. The major part of these reserves are classified proved undeveloped. See the discussion in "Proved Undeveloped Reserves" section.

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

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As of December 31, 2013, Eni s proved reserves booked for the Kashagan field amounted to 565 mmBOE, barely unchanged from 2012.

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

As of December 31, 2014, the aggregate costs incurred by Eni for the Kashagan project capitalized in the financial statements amounted to $8.5 billion (euro 7.0 billion at the EUR/USD exchange rate of December 31, 2014). This capitalized amount included: (i) $6.2 billion relating to expenditure incurred by Eni for the development of the oilfield; and (ii) $2.3 billion relating primarily to accrue finance charges and expenditures for the acquisition of interests in the North Caspian Sea PSA Consortium from exiting partners upon exercise of pre-emption rights in previous years.

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

In 2015, production of the Karachaganak field averaged 239 KBBL/d of liquids (56 net to Eni) and 858 mmCF/d of natural gas (199 net to Eni). This field is developed by producing liquids from the deeper layers of the reservoir. The gas is marketed (about 48%) at the Russian gas plant in Orenburg and the remaining volumes is utilized for re-injecting in the higher layers and the production of fuel gas. Approximately 93% of liquid production are stabilized at the Karachaganak Processing Complex (KPC) with a capacity of approximately 250 KBBL/d and exported to Western markets through the Caspian Pipeline Consortium (Eni s interest 2%) and the Atyrau-Samara pipeline. The remaining volumes of non-stabilized liquid production (approximately 16 KBBL/d) are marketed at the Russian terminal in Orenburg.

In June 2015, the Gas Sales Agreement for the Karachaganak field was extended until 2038. The agreement provides the supply of currently produced gas volumes to the Orenburg treatment plant, including additional new development projects to support the current liquids and gas production.
The Expansion Project is currently under study. The project targets to install, in stages, the gas treatment plants and re-injection facilities to support liquids production profile. The development plan is currently in the phase of technical

and marketing definition of its first development phase, aimed to increase the capacity of gas re-injection.

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

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

As of December 31, 2013, Eni s proved reserves booked for the Karachaganak field amounted to 470 mmBOE, barely unchanged from 2012.

Rest of Asia

In 2015, Eni s operations in the rest of Asia accounted for 8% of its total worldwide production of oil and natural gas.

China. Eni has been present in China since 1984 with activities located in the South China Sea. In 2015, Eni s production amounted to 3 KBOE/d.

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

In 2015, hydrocarbons were produced from the offshore Blocks 16/19 through 3 platforms connected to an FPSO.

Indonesia. Eni has been present in Indonesia since 2001. In 2015, Eni s production mainly composed of gas, amounted to 14 KBOE/d. Activities are concentrated in the Eastern offshore and onshore of East Kalimantan, offshore Sumatra, and offshore and onshore of West Timor and West Papua; in total, Eni holds interests in 14 blocks.

Exploration and production activities in Indonesia are regulated by PSAs.

The ongoing development activities that will ensure gas supplies to the Bontang liquefaction plant include: (i) the Jangkrik project (Eni operator with a 55% interest) in the Kalimantan offshore. This project provides for the drilling of production wells linked to a Floating Production Unit for gas and condensate treatment, as well as the construction of transportation facilities. Start-up is expected in 2017; and (ii) the Bangka project (Eni s interest 20%) in the Eastern Kalimantan, with start-up expected in 2016.

In June 2015, Eni and its partners of the Jangkrik project signed two agreements with PT Pertamina for the purchase and sale of 1.4 mmtonnes/y of LNG coming from Jangkrik field development project, starting from 2017.

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

Iran. Eni has been operating in Iran for several years under four Service Contracts (South Pars, Darquain, Dorood and Balal, these latter two projects being operated by another international oil company) entered into with the NIOC between 1999 and 2001, and no other exploration and development contracts have been entered into since then. All above mentioned projects have been completed. In 2015, Eni s contractual reimbursements were equivalent to a production of 22 KBBL/d, approximately 1% of the Group s worldwide production. Eni believes that its activities in Iran are marginal to the Group s results of operations and cash flow. For further information on this matter, see "Disclosure pursuant to Section 13(r) of the Exchange Act".

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

Development and production activities at the Zubair field are regulated by a technical service contract. This contractual scheme establishes an oil entitlement mechanism and an associated risk profile similar to those applicable to Production Sharing contracts.

In 2015, production of the Zubair field averaged 40 KBBL/d net to Eni.

The first stage of development activities (Rehabilitation Plan) of Zubair field were substantially completed. At the beginning of March 2016, three new generation plants for the oil, gas and water treatment (Initial Production Facilities - IPF) started. Those plants together with existing restructured and modernized facilities increased oil and natural gas treatment capacity of Zubair field to approximately 650 KBBL/d and will ensure the maximization of the associated gas utilization. In addition, these new facilities have also a water re-injection capacity of approximately 300 KBBL/d that will boost the Zubair s hydrocarbons production.

The Zubair project includes an additional development phase (Enhanced Redevelopment Plan), started in 2014, to achieve a production plateau of 850 KBBL/d.

In September 2015, Occidental of Iraq Llc, a partner of Eni BV Iraq in Zubair project, announced to exit the Zubair project, and in December 2015, SOC, the Iraqi state oil company, expressed its decision to take the place of the Occidental of Iraq Llc as a part of the project. Negotiations are underway between the parties involved.

Myanmar. In March 2015, Eni signed two Production Sharing Contracts for offshore blocks MD-02 and MD-04 (Eni operator with an 80% interest in both leases). The contracts foresee a study period of two years, followed by an exploration period of six years, subdivided in 3 phases.

Pakistan. Eni has been present in Pakistan since 2000. In 2015, Eni s production mainly composed of gas amounted to 39 KBOE/d.

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

Eni s main permits in the country are Bhit/Bhadra (Eni operator with a 40% interest), Sawan (Eni s interest 23.68%) and Zamzama (Eni s interest 17.75%), which in 2015 accounted for 75% of Eni s production in Pakistan.

Production optimization through infilling activities represents the main activity currently performed in the above listed fields to mitigate the natural field production decline.

Exploration activities yielded positive results with the Latif South 1 discovery well.

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

The activity was temporary and partially suspended after the restrictive EU and U.S. sanctions targeting the Russia-Ukraine crisis that were issued in summer 2014.

Following the adoption of these measures, Eni started the required authorization before competent Authorities of the Member States of the European Union who granted the Company certain authorization for the execution of exploration activities in Russia under the terms of pre-existing contracts.

In 2015, Eni has restarted the exploration activity in line with the existing restrictive measures. For further information on this matter, see "Item 3 Risk factors".

Turkmenistan. Eni started its activities in Turkmenistan with the purchase of the British company Burren Energy plc in 2008. Activities are focused on the onshore Nebit Dag Area in the Western part of the country. In 2015, Eni s production averaged 10 KBOE/d.

Exploration and production activities in Turkmenistan are regulated by PSAs.

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

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

Americas

In 2015, Eni s operations in Americas area accounted for 9% of its total worldwide production of oil and natural gas.

Ecuador. Eni has been present in Ecuador since 1988. Operations are performed in Block 10 (Eni s interest 100%) located in the Oriente Basin, in the Amazon forest. In 2015, Eni s production averaged 11 KBBL/d.

Exploration and production activities in Ecuador are regulated by a service contract that expires in 2033, following a ten-year extension signed in December 2015.

Block 10 production is processed by a Central Production Facility and transported to the Pacific Coast through a pipeline network.

Mexico. In December 2015, Eni signed the Production Sharing Contract as operator of the Block 1 (Eni s interest 100%) to develop the Amoca, Miztón and Tecoalli fields, located in the Gulf of Mexico shallow waters. The delineation campaign of the fields was submitted to the Mexican Authorities in the first quarter of 2016 and plans the drilling of four wells in order to define a fast track and synergic development plan.

Trinidad and Tobago. Eni has been present in Trinidad and Tobago since 1970. In 2015, Eni s production averaged 70 mmCF/d. Eni owns a 17.3% interest in the North Coast Marine Area 1 Block, located offshore North of Trinidad.

Exploration and production activities in Trinidad and Tobago are regulated by PSAs.

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

United States. Eni has been present in the United States since 1968. Activities are performed in the shallow and deep offshore of the Gulf of Mexico, onshore and offshore in Alaska, and in Texas onshore.

In 2015, Eni s oil&gas production was 96 KBOE/d mainly from the Gulf of Mexico and Alaska fields.

Exploration and production activities in the United States are regulated by concessions.

Eni holds interests in 128 exploration and production blocks in the Gulf of Mexico, of which 73 are operated by Eni.

The main operated fields are Allegheny and Appaloosa (Eni s interest 100%), Pegasus (Eni s interest 85%), Longhorn, Devils Towers and Triton (Eni s interest 75%). Eni also holds interests in Europa (Eni s interest 32%), Medusa (Eni s interest 25%), Thunder Hawk (Eni s interest 25%) and Frontrunner (Eni s interest 37.5%) fields.

As part of Eni s portfolio rationalization process, the sale of certain minor assets in the Gulf of Mexico was finalized.

During the year, production start-ups were achieved in the Gulf of Mexico at: (i) the Hadrian South field (Eni s interest 30%), with an estimated daily production of approximately 300 mmCF of gas and 2,250 BOE (about 16 KBOE/d net to Eni); and (ii) the Lucius field (Eni s interest 8.5%), with an estimated production of approximately 7 KBOE/d net to Eni. At the beginning of 2016 production start-up was achieved at the Heidelberg project (Eni s interest 12.5%) in the deepwater Gulf of Mexico. Production plateau is expected to reach approximately 9 KBOE/d net to Eni. Planned development activities progressed.

Other development activities concerned the drilling activities at the operated Devil s Tower field as well as at non-operated fields Medusa, K2 (Eni s interest 13.39%) and St. Malo (Eni s interest 1.25%).

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

Eni holds interests in 61 exploration and development blocks in Alaska, with interests ranging from 30 to 100%; Eni is the operator in 40 of these blocks.

Eni s production is provided by Nikaitchuq (Eni operator with a 100% interest) and Oooguruk (Eni s interest 30%) fields with a 2015 overall net production of approximately 25 KBBL/d.

Drilling activities progressed at the Nikaitchuq and Oooguruk fields.

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

Exploration activities yielded positive results with the Puckett Trust 1H well, within the agreement signed with Quicksilver Resources for joint evaluation, exploration and development of unconventional oil reservoirs (shale oil) in the southern part of the Delaware Basin, in West Texas. The discovery has already been connected to the existing production facilities.

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Venezuela. Eni has been present in Venezuela since 1998. In 2015, Eni s production averaged 24 KBOE/d.

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

Exploration and production of oil fields are regulated by the terms of the so-called Empresa Mixta. Under the new legal framework, only a company incorporated under the law of Venezuela is entitled to conduct petroleum operations. A stake of at least 60% in the capital of such company is held by an affiliate of the Venezuela state oil company, PDVSA, preferably Corporación Venezuelana de Petróleo (CVP).

Eni s production comes from the Corocoro field (Eni s interest 26%), in the Gulfo de Paria, and the Junin 5 field (Eni s interest 40%), located in the Orinoco Oil Belt.

In addition, in July 2015, production started at the gas giant Perla field, located in the Cardon IV block (Eni s interest 50%) in the Gulf of Venezuela. The gas will be mainly used by PDVSA for the domestic market, under the Gas Sales Agreement running until 2036. The development of Perla has been planned in three phases with 21 wells and the installation of four offshore platforms linked via sealine to an onshore treatment plant. The production level at the year-end was approximately 500 mmCF/d at 100%. The second phase will ensure production ramp-up at approximately 800 mmCF/d. The development plan targets a long-term production plateau of approximately 1,200 mmCF/d through a third phase of development.

Drilling activities progressed at the giant Junin 5 oilfield. Possible optimization of development program is currently under evaluation.

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

Australia and Oceania

Eni s operations in Australia and Oceania area are conducted mainly in Australia. In 2015, the area of Australia and Oceania accounted for 1% of Eni s total worldwide production of oil and natural gas.

Australia. Eni has been present in Australia since 2001. In 2015, Eni s production of oil and natural gas averaged 25 KBOE/d. Activities are focused on conventional and deep offshore fields.

Exploration and production activities in Australia are regulated by concession agreements, whereas in the cooperation zone between Timor Leste and Australia (Joint Petroleum Development Area - JPDA) they are regulated by PSAs.

The main production blocks in which Eni holds interests are WA-33-L (Eni s interest 100%), JPDA 03-13 (Eni s interest 10.99%) and JPDA 06-105 (Eni operator with a 40% interest). In the appraisal and development phase Eni holds interests in NT/P68 (Eni s interest 100%) and NT/RL7 (Eni s interest 32.5%). In addition Eni holds interest in 6 exploration licenses, of which 1 in the JPDA.

In JPDA 03-13, the phase 3 of the Bayu Undan field was completed in order to increase liquids production and to sustain LNG production.

Capital expenditures

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

Transparency on payments made to Governments for the purpose of the commercial development of hydrocarbons

In the matter of transparency of payments made to Governments in the extraction of hydrocarbons, Eni has been working to voluntarily achieve a higher degree of disclosure on payments, alongside the Company s continued support to the Extractive Industries Transparency Initiative (EITI), anticipating the reporting obligations on payments transparency established by EU Directive No. 2013/34 which the Italian legislator has enacted with Legislative Decree No. 139 of August 18, 2015 effective for payments made on or after January 1, 2016 to be reported in 2017. Therefore information provided below has been furnished on voluntary basis and does not constitute compliance with any reporting obligations. In particular, as Eni believes that the active involvement of governments is key to a sustainable use of revenues, the Company has reached out to all its counterparts in upstream contracts in order to share the Company s commitment on transparency and request their consent on disclosing taxes, royalties and the other forms of payment foreseen by the EITI Standard and the EU Directives.

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Therefore, Eni voluntarily discloses payments (on a cash basis) to governments (including to local authorities and other governmental authorities) for the year 2015. Payments refer to those countries whose governments/local authorities/governmental counterparts provided consent to this disclosure. Data in the following table correspond to the Company s accounting records and include data for the parent company and consolidated subsidiaries. Payments to governments referring to petroleum activities operated by Eni are disclosed on a 100% basis, when Eni paid on behalf of the Joint Venture partners. Payments made by Joint Venture partners on behalf of Eni in those activities where Eni is not the operator are not reported. We believe that those payment categories are in line with EITI Standard and EU Directives payment categories. The following disclosure represents approximately 75% of Eni s 2015 production (80% when including the two countries adhering to EITI listed below).

(euro thousands)	Year	Host government s entitlement	National Oil Companies entitlement	Profit taxes	Royalties	Bonus	Fees	Other significant payments and benefits	Capital expenditure (*)	Revenues from sales of equity hydrocarbons (*)